INSTITUTIONAL, REGULATORY AND COOPERATIVE FRAMEWORK MODEL FOR THE NILE BASIN POWER TRADE

ANNEX 7: DELIVERABLE 8 – "GRID CODE; GUIDELINES, PRINCIPLES AND SCOPE"

PREPARED FOR:

NILE BASIN INITIATIVE

" TO ACHIEVE SUSTAINABLE SOCIO-ECONOMIC DEVELOPMENT THROUGH THE EQUITABLE UTILIZATION OF, AND BENEFIT FROM, THE COMMON NILE BASIN WATER RESOURCES "

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I PROCEDURES AND GUIDELINES FOR A GRID CODE

1. INTRODUCTION

1.1. ABOUT THIS REPORT

This report is Deliverable 8 "A report of the proposed Grid Code and Guidelines for reporting process" and corresponds to Activity 6 "Reporting and Information Exchange for the Implementation of Power Trade" of the revised terms of reference of the project agreed during the inception mission in Dar es Salaam.

The purpose of this report is to present procedures and guidelines for a regional Grid Code. In the TOR the scope of work for this report is covered in activity 6:

> *"Establish the reporting processes and requirements, and information exchange protocols necessary for the implementation of the initial stages of a Power Trade regime including guidelines for a regional grid code"*

As it can be observed two different issues can be distinguished in this scope: one dealing with the reporting processes and information exchange (in general terms), and one specifically dealing with guidelines for a grid code.

This report will present the proposed guidelines for a regional grid code and those for reporting processes and information exchange protocols between/among members participating in the Power Trade (as indicated in the Deliverable's description in Section IV Deliverables of the Revised Terms of Reference). That is to say, the report will include a section on the information exchange procedures that correspond to, and are typical of, grid codes.

The rest elements of the scope, issues dealing with reporting processes, general information exchange, etc., are included in deliverable 9, this way developing the entire topic of information management in one deliverable. Otherwise, the same issue would be treated separately in two different deliverables.

The Nordic Grid Code will be attached as an example in this report. This code has been in use by Nordic TSOs for many years. It is revised every second year and the latest version from 2007 is fully available online at http://www.nordel.org/content/default.asp?pagename=openfile&DocID=4948.

The grid code proposed for the Greater Mekong Sub Region market is also attached as a separate annex; this provides two examples of grid code for quite different regions: one with a highly developed market, and one with a market trying to develop, bearing some regional characteristics similar to those of the NBI.

In general, the following three aspects of a Grid Code are presented in this report:

- The purpose of the Grid Code
- The contents (scope and structure) of the Grid Code
- The development of a Regional Grid Code and the shift of priorities in different phases of the development (from grid stability and security of supply to open access and facilitation of the regional power market, but still maintaining a focus on supply security)

It must be noted that, although the Nordic Grid Code is tailor-made for the Nordic Power Market, it has been unanimously decided by four different countries and Transmission System Operators (TSOs) , and the document forms thus, a live operational tool. In a NBI perspective it is important to understand the developments of this document as adapted to the different stages of the of the electricity market's development in the Nordic Countries.

It is fundamental for such a comprehensive document to always achieve a win-win situation for all involved countries.

1.2. Purpose of the Grid Code

The Grid Code forms the basis for co-operation between TSOs[1] (or neighbouring utilities). The purpose of the Grid Code is to achieve uniform and co-ordinated operation and planning between the TSOs in order to establish favourable conditions for the development of a well-functioning and effectively integrated Regional electricity market. An essential objective of the Grid Code is to set a common basis for satisfactory operational reliability and quality of supply in the coherent Regional electric power system.

The Grid Code governs technical co-operation between the TSOs in an interconnected Regional system. It concerns the operation and planning of the TSOs' electric power system and the market participants' access to the grid. The Grid Code lays down fundamental common requirements and procedures that govern the operation and development of the electric power system.

The final version or operative version of the Grid Code will have to be adapted to the agreed stages of Market Development proposed in Deliverable no. 7. However, no matter which form takes the final version, it is necessary to agree on the main principles; this document presents the guidelines and basic principles to develop later the operative version of the grid code.

The Regional Grid Code may serve different purposes, and the emphasis may vary depending on the state of regional grids and markets. Objectives include:

1. To define standards for operational reliability and quality of supply in the region.
2. To co-ordinate operation and planning between utilities in the region including ranking of planned investment projects in increased transmission capacities based on socio-economic criteria.
3. To facilitate the development of an integrated electricity market.
4. To implement agreements on transparency regarding essential market data[2].

2. CONTENTS OF THE GRID CODE

2.1. Overview

The components of a regional Grid Code are:

1. A description of the power system(s), institutional framework and general provisions
2. Planning Code
3. Operational Code (System Operation Agreement)
4. Connection Code
5. Data Exchange Code (Data Exchange Agreement)

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[1] In this report, the term "TSO" also includes all grid owners/operators regardless of unbundling status.

[2] The Nordic agreement between the 4 TSOs and the Nord Pool power exchange for publication of market data will be used as an example. A new revision of this agreement was published in October 2007.

In the Nordel area, the various parts of the Grid Code have different status:

- The Operational Code and the Data Exchange Code are binding agreements.
- The Planning Code and the Connection Code are rules that should be observed.
- The Connection Code, binding rules are set for asset owners in national legislation and agreements.

In addition it would be important for the NB area to include a code for metering, especially on any interchange between member countries (between vertically integrated national utilities). Supplementing the meter code would result in a settlement regulation promoting cash rather than in kind settlement.

Also, how to manage disputes is a key chapter of a regional grid code. This should encourage the attempt to solve any dispute at the lowest possible level.

It is important to bear in mind that the Grid Code is a starting point for the harmonisation of national rules, setting the minimum requirements for technical properties that influence the operation of the interconnected electric power system. The Grid Code must, however, be subordinate to the national rules in the countries concerned.

It is also important to note that the Nordel organisation is not a participating in the Grid Code. The Parties are the National TSOs Statnett in Norway, Svenska Kraftnät in Sweden, Fingrid Oy in Finland and Energinet.dk in Denmark. The role of Nordel is that of facilitator for the Grid Code. Without the organisation working as an important meeting place for the TSOs, and also as a communication channel, it is not certain that it would have been possible to make the Grid Code.

As already mentioned, the Grid Code is subordinate to the national rules in the countries concerned. If the ambition was for the parties in the Grid to be a combination of Nordic TSOs and Nordic National Regulators, it is doubtful whether it would have been possible to develop the Nordic Grid Code this far.

The basis for the success of developing the Nordic Gride Code lies in a division of clear roles and responsibilities between the National Regulators, National TSOs and the Nordel-organisation.

2.2. Description of the power system, the Institutional Framework and General Provisions

This chapter of the Grid Code describes the infrastructure in terms of physical resources and installed equipment, and the legal frameworks and institutions in the power sector for the whole region, with particular focus on the goals and measures for regional co-operation.

This document will cover:

- Roles and responsibilities for institutions in the Nile Basin Area
- Legislation and regulation of the power sector
- Trading schemes and market places
- Demand profiles, energy/peak, and expected growth
- Generation capacity, energy mix and planned expansion
- Grid conditions and constraints
- Regional transmission capacities and expansion plans

The Grid Code must also have some general provisions concerning bilateral agreements, confidentiality, deviations from the regulations in the Grid Code including dealing with unclear provisions in the regulation, and the developments of the Grid Code's regulations.

Although the Grid Code may not be binding in all aspects, it is the parties' intention that the bilateral contracts or similar arrangements are agreed, the rules and principles of the code must be followed to the greatest possible extent.

If information exchanged between parties has not been published in the country to which the information relates, the parties undertake to keep the information confidential as far as the legislation allows in the respective country.

If a TSO chooses not to follow the recommendations of the Planning Code and the Connection Code, the other TSO must, if this is possible and necessary, be informed before the deviation takes place. The System Operation Agreement and the Data Exchange Agreement are binding agreements between parties, with specific dispute solutions.

The Grid Code must be updated regularly. Updating must take place when necessary; however the Code must be reviewed at least once a year.

2.3. PLANNING CODE

The Planning Code describes higher-level and common regional requirements, processes and criteria for joint planning.The objective of the Planning Code is to provide a basis to secure the following:

- Cohesion in the regional electric power system
- Reliability in the regional electric power system, including system security and system adequacy
- A functioning regional electricity market
- Environmental considerations

Important criteria for planning are:

- Production optimization and energy turnover
- Less risk of energy rationing
- Less risk of power shortage
- Changes in active and reactive losses
- Trading in regulating power and system services
- Sufficient capacity

The Intention is that the power system shall be designed so that electric power consumption can be met at the lowest cost. This means that the power system shall be planned, built and operated so that sufficient transmission capacity will be available for utilizing generation capacity, and meeting consumer needs in an economically best way.

The Grid Code should allow for well-performing joint operation. This demands coordination, both in the planning of the power system and the operating stage.

2.4. OPERATIONAL CODE

Objectives:

1. To make use of the advantages arising from the interconnected operation,
2. To define standards for reliability and quality of supply.

Scope of the Operational Code:

- Security standards and system protection
- Balance regulation
- Information exchange
- System services, e.g.
    - Operational reserves
    - System restoration
- Management of transmission links within the region
- Management of external transmission links

The Operational Code is a binding agreement. The parties in the Operational code will be the TSOs/the Neighbouring utility. The Parties shall jointly uphold the interconnected operation of the Regional Power System at a satisfactory level of reliability and quality.

These Parties shall jointly operate the interconnected Regional system in a manner that promotes efficient utilization of existing resources and power trading on the Regional market, as well as on additional potential international market. The Agreement specifies in detail the commitments that the Parties undertake to honour during their operational collaboration.

The Parties may agree that agreements regarding the interconnected Regional system shall only be made between the TSOs concerned. Each Party shall enter into such agreements with companies within its own subsystem, as it is necessary to comply with the Agreement.

2.5. CONNECTION CODE

The objective of the Connection Code is to define rules for connection to the transmission system on non-discriminating terms.

The Connection Code specifies minimum technical requirements to ensure security of operation in the regional electric power system. National rules may be stricter.

Scope of the Connection Code:

- Connection to the grid
    - System frequency
    - Voltages and voltage variations
    - Outages
- Generation
- Grids
- HVDC
- Wind turbines

The Connection Code may apply to new installations or to the reconstruction of existing ones. Existing installations must retain the properties they owned when they were connected to the grid.

2.6. DATA EXCHANGE CODE

The objectives of the Data Exchange Code are:

1. To facilitate system analyses of the interconnected regional power system for dealing with balance and capacity problems,

2. To control the distribution of the models that are used to analyze the regional power system.

Data concerning production plants are considered commercial, and treated as confidential.

Scope of exchanged data:

- <u>Production</u> data for different types of plants (hydro, thermal etc)
    - Technical data:
        - Efficiencies, capacities, availability
        - Fuel type, environmental conditions
        - For hydro power: reservoir volume and usage limitations
        - Financial data: Operation and maintenance costs

- <u>Consumption</u> data:
    - Annual consumption,
    - year profile
    - peak load

- <u>Grid and transmission</u> data:
    - Transmission capacities, losses, availability, grid tariffs.

The data exchange agreement applies to the basis of, and data for, the grid model and enables multi area power market simulation jointly between the TSOs. Grid Models and Multi Area power market simulators may be freely used for studies by the parties of the Agreement. The scope of data for the Grid Models and for the Multi Area market simulators can be defined.

Exchange of data to consultants is regulated in this agreement and needs consent from the Parties of the Agreement. A draft agreement – Power System Data – Use of Consultants, can be enclosed.

3. DEVELOPMENT PROCESS OF A REGIONAL GRID CODE

The Grid Code will be based on the requirements from the bilateral contracts/Power Exchange Agreements between neighbouring TSOs. The Grid Code must also be coherent with the different national regulations and National Grid Codes developed by the Regulator and/or the TSO.

This means that the approach in developing a Regional Grid Code must be very flexible and must link to the work of the regional TSOs. It is very difficult to imagine one common Grid Code for the whole NBI for the next 10 or 20 years. The start would involve neighbouring countries already interconnected, and a Power Exchange Agreement. The further development of a Grid Code should keep up with plans for investments in new interconnections.

The example from the Nordic Area shows a gradual development and integration of a Nordic Cooperation. The first one based on bilateral contracts dates back to 1912. Several bilateral contracts and interconnections have followed since then.

In 1963, the planning and construction of the joint interconnections led to greater contact between the electricity companies in the Nordic countries, and an organisation, Nordel, was established to create a more harmonised program for the future Nordic Cooperation.

As the rapidly growing electric power system would be connected to relatively weak transmission links, Nordel had to solve control and stability problems. The long-term solution was to make transmission links stronger. Nordel's recommendations formed the basis of the technical regulations for production and grid operations in the Nordic Countries.

Admittedly, the recommendations were not formally binding, however, since they were accepted jointly and unanimously, the rules were respected by all parties and came to set the foundations for any formal regulation required in the individual countries.

The change in Electricity Market since the beginning of the 1990's also changed the preconditions for Nordic Cooperation. In 1998 the Nordel was to be a cooperation organisation for the TSOs after a change of the statutes. Another change in June 2000 transformed the organisation into a cooperation organisation with the stated objective of creating conditions for an efficient and harmonised Nordic Electric Market, and of further developing the market. Once a body for cooperation between integrated power companies, Nordel was now a body for cooperation between transmission system operators.

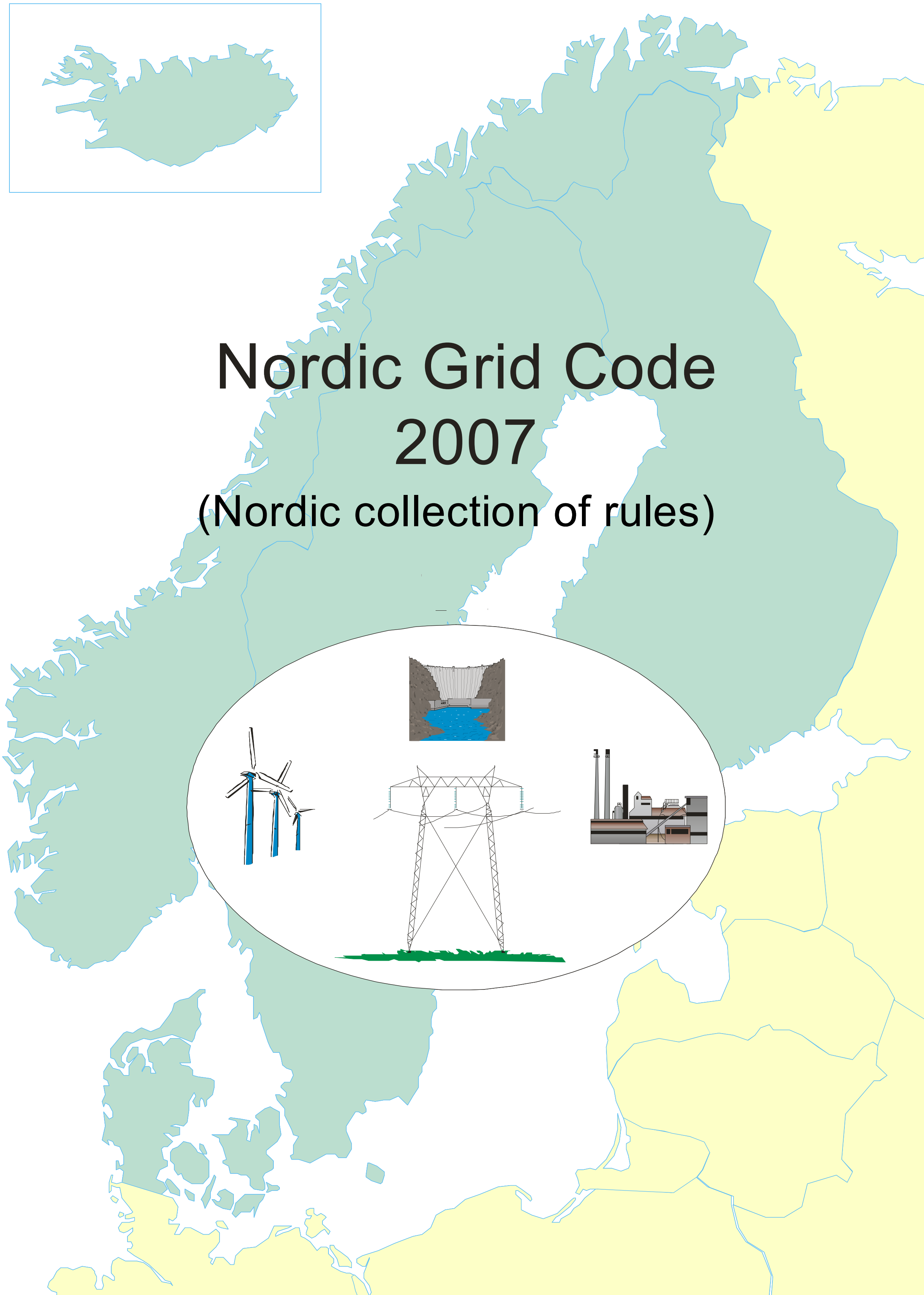
Based on the experience from the NBI countries we find a large variety of development stages compared to the Nordic Experience. Some are still isolated systems and some have practised a bilateral trade in more than 50 years, between Kenya and Uganda.

It is very hard to imagine one common Grid for the whole area in the next decade. The approach must be flexible, based on the actual experience from bilateral trade in the NBI area. In that respect the TSOs/Utilities in the NBI organisation must play a fundamental role in the development of a future NBI Grid Code.

Annex: Nordic Grid Code

Nordic Grid Code 2007

(Nordic collection of rules)



PREFACE

The transmission system operators (TSOs) in Denmark, Finland, Norway and Sweden have agreed to publish the Nordic Grid Code for the Nordic grid. The code is a collection of rules concerning the interconnected Nordic grids. It is the aim of the parties to develop the code. Future agreements concerning the interconnected Nordic grids should be incorporated.

The Nordic Grid Code must be updated when necessary, but in addition it must be reviewed at least once a year.

The Operational Code and the Data Exchange Code are binding agreements with specific dispute solutions. The Planning Code and the Connection Code are rules that should be observed. They correspond to Nordel's recommendations in these areas.

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The present document is the English translation of Nordisk regelsamling 2004 and its updated parts, which have been written and published in the Swedish language. In case of possible discrepancies between the English and the Swedish version, the Swedish version shall prevail.

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INTRODUCTION TO A COMMON NORDIC GRID CODE

1 Introduction

The formulation of this common code for the Nordic grid (the Nordic Grid Code) is a step towards the harmonisation of the rules that govern the various national grid companies. The purpose of the Nordic Grid Code is to achieve coherent and coordinated Nordic operation and planning between the companies responsible for operating the transmission systems, in order to establish the best possible conditions for development of a functioning and effectively integrated Nordic power market. A further objective is to develop a shared basis for satisfactory operational reliability and quality of delivery in the coherent Nordic electric power system.

The Nordic Grid Code concerns the transmission system operators (TSO's) the operation and planning of the electric power system and the market actors' access to the grid. The Code lays down fundamental common requirements and procedures that govern the operation and development of the electric power system.

The Nordic Grid Code is made up of:

- General provisions for cooperation
- Planning Code
- Operational Code (System Operation Agreement)
- Connection Code
- Data Exchange Code (Data Exchange Agreement between the Nordic transmission system operators (TSOs)

The Operational Code and the Data Exchange Code are binding agreements with specific dispute solutions. The Planning Code and the Connection Code are rules that should be observed. They correspond to Nordel's recommendations in these areas.

The Nordic Grid Code governs technical cooperation between the transmission system operators in the interconnected Nordel countries: Norway, Sweden, Finland and Denmark.

Ideally, the planning, expansion and operation of all the subsystems would be governed by identical rules. However, this is not yet the case, partly for historical reasons and partly because the different subsystems are subject to different legislation and to supervision by different official bodies. However, an objective is that the Nordic Grid Code should be a starting point for the harmonisation of national rules, with minimum requirements for technical properties that influence the operation of the interconnected Nordic electric power system. The Nordic Grid Code must, however, be subordinate to the national rules in the various Nordic countries, such as the provisions of legislation, decrees and the conditions imposed by official bodies.

The first edition of the Nordic Grid Code was based on Nordel's former rules (recommendations), the system operation agreement, the Data Exchange Agreement and national codes. Therefore the content of the Code still shows traces of being taken from numerous sources.

The new versions of the System Operation Agreement and the Data Exchange Agreement are reproduced in this edition in their entirety. As a new Nordel recommendation this document includes the Nordel Connection Code for Wind Turbines. It is included as an own chapter in the Connection Code. Other parts of the Connection Code have been updated according to the latest development in the national requirements and rules. Coordination between the Planning Code and the Operational Code has been improved by developing the formulation of the criteria scheme in planning to better correspond with the operational states.

The development of the Nordic Grid Code is a project that ought to continue also in the years ahead. The work on further development of Nordic cooperation to the Nordic electric power market thus continues.

2 Background

2.1 Nordic cooperation

The expansion of electric power supply in the Nordic countries began at the end of the 19th century and at the beginning of the 20th. To begin with, small local electrical companies were set up. Gradually these companies merged in order to become larger regional units. Eventually, the systems developed to the point where the power grids in the individual Nordic countries were linked via high-voltage interconnections.

From the outset, the supply of electric power in the Nordic countries was based on different sources of energy. In Norway and Sweden, hydro-electric power was the main energy source. Finland used a mix of hydro and thermal power, whilst Denmark’s energy supply was based almost entirely on thermal power. Companies and official bodies in the Nordic countries soon realised that there were significant benefits to be gained from collaborating and utilising whichever energy source was the most advantageous at the time in the various countries. Furthermore cooperation resulted in improved security of supply.

Already in 1912 the first inter-Nordic interconnection operation agreement was signed. Sydkraft in Malmö and NESA in Copenhagen agreed that Sydkraft would supply surplus power from its power plants to Zealand in Denmark. On 15 November 1915 a 25,000 volt AC cable between Skåne and Zealand was ready to go into service. Cooperation on electric power between Sweden and Norway began much further north with the opening of the railway between Kiruna and Narvik in the early 1940s.

In 1929 a 60 kV AC interconnection was built between Jutland and Northern Germany. Over the years from 1930 to 1960, further opportunities for cooperation were investigated, however, without result until 1959, when an AC interconnection between Sweden and Finland went into service. In 1960, new interconnections between Sweden and Norway were completed and a joint power plant project was implemented on the Linnvass river (Linnvassälven). Five years later, in 1965, an HVDC cable was laid between Jutland and the west coast of Sweden. Electrical interconnections to the east were extended in 1961 with an AC transmission line across the eastern border of Finland to the Soviet Union. In 1976 an HVDC link was installed between Norway and Jutland; its capacity was increased in 1993. The Fenno-Skan HVDC link between Sweden and Finland was built in 1989.

The planning and construction of the joint interconnections led to greater contact between the electricity companies in the Nordic countries, and in 1963, Nordel, a Nordic cooperation program in the field of electric power supply, was established.

During the 1960s, electric power consumption increased considerably in all the Nordic countries. The opportunities for cooperation, for linking together different kinds of production resources and for creating shared production reserves also attracted greater attention. The members of Nordel were seeking benefits from coordinating the expansion and operation of the grids.

As the rapidly growing electric power system would be connected to relatively weak transmission links, Nordel had to solve problems of control and stability. The long-term solution was to make the transmission links stronger. Nordel's recommendations formed the basis of the technical regulations for production and grid operations in the Nordic countries. Admittedly, the recommendations were not formally binding, however, since they were accepted jointly and unanimously, the rules were complied with by all parties and came to provide the foundation for any formal regulations required in the individual countries.

A feature of cooperation within Nordel has been a common will to find solutions which create good preconditions for utilising the technical, environmental and economic advantages that result from an effective common system. From the outset, the sector and electricity users over the entire Nordel area has benefited from this basic idea.

In order to increase efficiency in the electrical sector, the Nordic countries chose, starting in 1991 in Norway, to expose electricity production and trading to competition and to separate these functions from the still regulated natural grid monopoly. Since the 1980s, there has been a trend towards free competition both in the EU and elsewhere in the world, but the trend has developed most rapidly in the Nordic countries. Among other things, the world's first international electric power exchange, Nord Pool, was launched here in 1996. Factors that contributed to the rapid development of the open common Nordic electric power market were a well-functioning electric power system and a good tradition of cooperation, partly within Nordel.

The changes in the electricity market also changed the preconditions for Nordic cooperation. Nordel took its first step towards adaptation to the changes in 1993, when, among other things, the organisation changed its statutes to correspond better to the structure that emerged when the grid operations of the companies were separated from the rest of their operations. The changes supposed that both the grid sector and the production sector still should be represented in Nordel. The importance of continued cooperation between the sectors on technical system issues, for example, was emphasised.

The starting point for a further change to the statutes in 1998 was that Nordel would be a cooperation organisation for the transmission system operators in the Nordic countries and should provide a platform for cooperation. At the same time, market actors with technical installations of significance for the electric power system would continue to collaborate within the organisation. Yet another change to the statutes in June 2000 transformed Nordel into an organisation for the transmission system operators in the Nordic countries, with the stated objective of creating the conditions for an efficient and harmonised Nordic electricity market, and of developing that market further. Once a body for cooperation between integrated power companies, Nordel was now a body for cooperation between transmission system operators.

The number of physical interconnections between the Nordel region and neighbouring countries is increasing. In 1982, an HVDC link was installed between Finland and the Soviet

Union. There are now HVDC links to Germany from both Sweden and Denmark and since 2000 an HVDC cable between Poland and Sweden. The AC interconnections between Western Denmark and Germany have been expanded continuously. Since 2000, a 450 MW Russian power plant in St. Petersburg has been connected directly to the Finnish subsystem. The increasing number of interconnections brings growing need for coordination. In its capacity of cooperation organisation for transmission system operators, Nordel is a natural forum for contacts between the Nordic electric power system as a whole and system operators elsewhere. In addition, as a forum for technical cooperation, Nordel offers a unique opportunity for utilising the expertise that is also needed in international work.

Nordel operates non-bureaucratically. The posts in the organisation rotate between the Nordic grid operating companies. The company represented by the chairperson is responsible for the secretariat and bears the associated costs; this makes it possible for Nordel to have no budget of its own. Nordel uses no interpreters. The member companies provide human resources; a key factor in Nordel's work is the core specialist expertise that the companies make available.

2.2 The Nordic electric power system

In the Nordic countries, production systems differ greatly from one country to another. Denmark uses conventional thermal power and an increasing proportion of wind power. Norway has hydropower, whilst Finland and Sweden have a mix of different systems, mostly hydro and nuclear power.

Today, the Nordic grid comprises the national electric power systems of Denmark, Sweden, Norway and Finland, as well as several interconnections between the countries which tie the national grids together into a coherent system. This system constitutes a single area with a common frequency, with the exception of Western Denmark, which is interconnected with the grid that falls within the area of the continental cooperation organisation UCTE.

The subsystems in Finland, Norway, Sweden and eastern Denmark are interconnected synchronously and form what is known as the "synchronised system". The subsystem in Western Denmark is connected to Norway and Sweden via HVDC links. Together, the synchronous system and the Western Denmark subsystem form the interconnected Nordic electric power system.

The interconnection of the individual subsystems into a common system means increased security and lower costs. The delivery capacity of the system as a whole is higher than the sum of the individual delivery capacities of the subsystems. As a result of the expansion of transmission capacity between the subsystems, the interconnected Nordic electric power system operates increasingly as a single entity.

The common system reduces the need for reserves and improves the potential for obtaining help in the event of serious disturbances or in other extreme situations such as years of exceptional drought or shortage of fuel.

A Nordic grid that works well is the technical prerequisite for a secure Nordic supply of high-quality electric power, and has been the foundation of a financially and environmentally efficient power supply.

2.3 The electrical characteristics of the Nordic electric power system

The following AC voltage levels are used in the Nordic grid (there are also interconnections at lower voltages across national borders):

- Denmark: 132/150/220/400 kV
- Finland: 110/220/400 kV
- Norway: 300/420 kV (and 132 kV in the north of Norway)
- Sweden: 220/400 kV

Between subsystems there are also HVDC links at 285-400 kV.

These transmission lines interconnect a number of generators:

- Hydro power production is concentrated in Norway and the north of Sweden and Finland.
- Thermal power production is concentrated in Denmark and the southern parts of Sweden and Finland.
- Wind power production and decentralised production are concentrated in Denmark. Particularly in the West of Denmark in, wind power accounts for a large part of total production.

The reactance of the AC transmission lines determines how strongly the system is coupled. Long transmission distances and relatively weak coupling between distant generators are typical features of the Nordel system.

Weak coupling between generators means that on some interconnecting links it is not possible to utilise the full thermal capacity. According to the Planning Code, it must be possible to maintain stable operation after the most common types of fault. This applies to transient, dynamic and static stability for both frequency and voltage conditions, and no consequential tripping shall take place due to overloading of components.

Because of long transmission distances and high reactances, it is usually insufficient voltage support and/or insufficient damping that sets limits on transmission between subsystems. With excessive power transmission, either voltage collapse would occur (voltage stability) or generators would lose synchronism (angle stability) because of a single fault condition. This may occur with significantly lower transmitted power than the grid components themselves could tolerate (thermal capacity).

Another feature of long transmission distances and separate generators is that the ability of certain interconnections to transmit power depends on the direction of the power flow, and varies over the year, depending, for instance, on which generators are connected to the grid and how much power is being transmitted on other parts of the grid. The technical transmission limit is determined by grid simulations in different operating modes. Naturally there must be a system safety margin in terms of calculation accuracy. In addition, some of the technical transmission capacity is reserved for control margin used for system services, for instance. The remaining part of the capacity is put at the disposal of the electricity market and is known as the commercial capacity.

The main cross-sections where experience has shown that physical limitations on the Nordic electricity market may arise are (see the Planning Code):

- Denmark: In Western Denmark there are interconnections to Norway, Sweden and Germany and two internal cross-sections (A and B), which may limit import from

Norway, and Sweden. In Eastern Denmark the link between Zealand and Sweden may impose a limit. Transmission lines in Sweden's internal cross-sections (cross-section 4 and the west coast cross-section) also have a major impact on capacity there.

- Finland: There is one internal cross-section, P1, and two cross-sections to Sweden, RAC and RDC. Depending on the operating situation, it is voltage stability, insufficient damping or thermal limits that limit transmission in these cross-sections.
- Norway: There are five internal cross-sections and the Hasle cross-section to Sweden. In particular the latter cross-section has proved in practice to be important for conditions on the Nordic electricity market. In this cross-section, transmission is limited by voltage and/or angle stability.
- Sweden: There are three important main cross-sections (1, 2 and 4) and the west coast cross-section. The capacity of the main cross-sections is limited by voltage and/or angle stability, whilst the west coast cross-section is limited by thermal capacity.

Where the limit is imposed by the stability conditions, it may be possible to boost the transmission capacity without building new transmission lines. To improve voltage stability, fast-response reactive power can be installed, for example series capacitors or controllable shunt capacitors. Controllable grid components, such as controlled series and shunt capacitors and HVDC links, may be used to improve damping. Another option is to install a system protection which disconnects some production units or loads after certain types of fault, thus reducing the power transmitted on critical interconnections.

Since stability issues are highly important for the Nordel network, it is essential for production units to be able to tolerate different types of fault on that network. Uncontrolled tripping of generators in the event of grid faults might make the instability even worse. Stability on the Nordel network can be improved and its transmission capacity can be increased by optimising the voltage regulators and power system stabilisers of the generators. For these reasons it is important for Nordel to have a common Connection Code that lays down minimum requirements for the technical characteristics of production units.

2.4 Transmission system operators (TSOs)

In Denmark, Finland, Norway and Sweden, transmission system operators (TSOs) have been appointed, with overall responsibility for ensuring that every subsystem works properly. These TSOs are Energinet.dk for the Danish subsystem, Fingrid Oyj for the Finnish subsystem, Statnett SF for the Norwegian subsystem and Affärsverket Svenska Kraftnät for the Swedish subsystem.

The TSOs in the Nordic countries are required to operate within the framework of the rules laid down in national and EU law. Some of the higher-level frames are the same for all countries, however these may be interpreted differently. The frames also change with political developments.

The first system operation agreement between two Nordic TSOs was made in 1996 between Statnett and Svenska Kraftnät. This agreement was followed by bilateral system operation agreements between all TSOs. The first Nordic system operation agreement between all Nordic TSOs, with the exception of the TSO on Iceland, was made in October 1999.

2.5 The Nordic electricity market[1]

The Nordic market is an international market. The electric power system and functions of the market influence each other. The market structure in Nordel's neighbouring countries differs from the structure in the Nordic countries; this, together with the development of their production and consumption, is also significant for the Nordic electric power system.

There is a physical market and as well a financial market. For the grid, the physical market is of interest and is outlined below.

2.5.1 Elspot

The Elspot market deals with power contracts for physical delivery daily within 24 hours. Elspot's price mechanism is used to regulate the flow of power where there are capacity limitations in the Norwegian grid and between the individual countries. Therefore Elspot may be regarded as a combined energy and capacity market.

The price calculation is based on purchase bids and sale bids from all market actors.

2.5.2 Elbas

Elbas is an organised balance market for Sweden, Finland,Eastern Denmark and Germany. The Elbas market comprises continuous power trading in hourly contracts up to two hours before physical delivery. The Elbas market complements Elspot and balance management by the TSOs.

2.5.3 The regulating power market

The TSOs in each area manage the unforeseen balance between production and consumption. The active actors who can create balance are consumers and producers, who can react quickly in situations with unexpected power deviation by rapidly adjusting their power take-off or by feeding in large amounts of power.

3 General provisions

3.1 Bilateral agreements

Where bilateral agreements or similar arrangements are agreed, the rules and principles in the code must be followed to the greatest possible extent.

3.2 Confidentiality

If the information exchanged between parties has not been published in the country to which the information relates, the parties undertake to keep the information confidential as far as the legislation allows in the respective country.

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[1] For a detailed description of the ways in which the Nordic electric power market works, see Nord Pool's website: www.nordpool.com

3.3 Deviations from the regulations

If a TSO chooses not to follow the recommendations of the Planning Code and the Connection Code, the other TSOs must, if this is considered possible and necessary, be informed before the deviation takes place. The System Operation Agreement and the Data Exchange Agreement are binding agreements between the parties, with specific dispute solutions.

3.4 Dealing with unclear provisions in the regulations

If there is disagreement about the validity, application or interpretation of the rules in this code, the issue shall be dealt with primarily in the respective Nordel committee. If agreement cannot be reached, the issue can be referred to Nordel's board for a ruling. Nordel's legal advisor group must always be consulted before an issue is referred in this way.

3.5 The development of the regulations

Nordel's Planning Committee is responsible, in consultation with Nordel's Operations Committee, for the continued work on and further development of the Nordic Grid Code. The Operations Committee is responsible for the Operational Code in particular.

The Nordic Grid Code must be updated regularly. Updating must take place when necessary, however the Code must be reviewed at least once a year. Nordel's legal advisor group must always be consulted before any decision is taken that involves significant changes to the Nordic Grid Code.

The following documents have been included in this chapter:

Document	*Status*
The Nordel Grid Master Plan 2002 (parts of)	*For information*
Prioritized cross sections	*For information*
Nordel's planning rules 1992	*Recommendations (desirable requirements)*
Planning Code 2004	*Recommendations*
Follow up on the Moberg report	*Approved in May 2006 by the Planning Committee and the Operations Committee*
Transmission capacities in the Nordel system – the 2005 stage, 1999	*Approved in 1998 by the Planning Committee and the Operations Committee*
Final report of Nordel's HVDC working group, 1998 and drafted recommendation	*For information*

The following national documents deal with the planning code:

Document	*Status*

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2 THE WORK OF PLANNING ... 17
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PLANNING CODE

All parts of the power system shall be designed so that the electric power consumption will be met at the lowest cost. This means that the power system shall be planned, built and operated so that sufficient transmission capacity will be available for utilising the generation capacity and meeting the needs of the consumers in a way which is economically best. This also presupposes suitably balanced reliability.

The long-term economic design of the grid means to balance between investments and the cost of maintenance, operation and supply interruptions, taking into account the environmental demands and other limitations. Flexible solutions which take into account future uncertainties, e.g. generation limitations, uncertain load development, technical development, etc., should be selected. In this evaluation socioeconomics as well as market functioning shall be included.

The Nordic main grid should allow for well-performing joint operation. This demands co-ordination, both in the planning of the power system and at the operating stage.

1 Purpose and target groups

Nordic planning work shall contribute to coherent and coordinated Nordic planning between the TSOs. It must secure the infrastructure that gives the best possible preconditions for an integrated Nordic market that works well and efficiently, both in spot market terms and regulating-power market terms. This must be done with due regard to the reliability of supply and the environmental targets of the individual countries.

The Planning Code describes higher-level and common Nordic requirements, frames, processes and criteria for joint planning. It also specifies the information necessary for planning, information which grid owners and producers must be obliged to provide to the TSOs.

The purpose is to provide a basis to secure the following by planning:

- cohesion in the Nordic electric power system
- reliability in the Nordic electric power system, including system security and system adequacy
- a functioning Nordic market
- environmental considerations

The target group is:

- TSOs in the Nordic countries
- Market actors
- Grid owners
- The authorities

2 The work of planning

The work of planning is generally constructed around:

- preconditions
  - imposed preconditions
  - the existing electric power system
  - generation system changes
    - concrete expansions (investment decisions have been taken)
    - forecast expansion
  - consumption change
    - concrete expansions (investment decisions have been taken)
    - forecast expansion
- events analysed under the given preconditions
- acceptable consequences for the given events

The work of Nordic planning includes both the need to extend the grid and the need for system services. Planning takes place on a higher level and therefore does not include the distribution networks. It is concerned only with the part of the transmission networks that are important for the interconnected Nordic electric power system. The method used to analyse present and necessary grid strengthening measures includes:

- clarification of preconditions, including relevant development scenarios
- system engineering analyses, including power/energy balance analyses and network analyses
- technical/economic comparison and evaluation. The economic evaluation is based on socio-economic theories.

This process is illustrated in Figure 1 below. The system engineering analyses (network and power/energy balance analyses) are done as an interactive process in which the results of the power/energy balances constitute the "input" to the network analyses and vice versa.

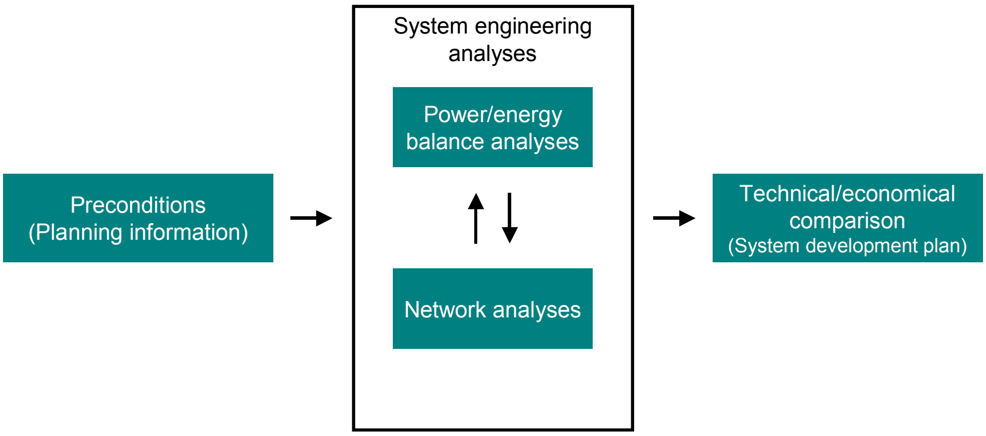


Figure 1 Sketch of the method for evaluation of the need for measures to reinforce the grid

Possible investments are evaluated on the basis of costs and benefit values. Socio-economic principles are used in the benefit evaluation. Important criteria for planning are:

1. Production optimisation and energy turnover
2. Less risk of energy rationing
3. Less risk of power shortage
4. Changes in active and reactive losses
5. Trading in regulating power and system services
6. The value of a better-functioning electric power market
7. Sufficient capacity

Examples of methods, models and tools are described in more detail in Appendix 1: Method, models and tools for system engineering studies.

3 Transmission capacity

3.1 Nominal transmission capacity for direct current

- The nominal transmission capacity is the maximum continuous power that can be allowed at an ambient temperature that is not exceeded for more than 4 weeks per year and without affecting the nominal availability.
- The nominal transmission capacity is measured on the AC side of the rectifier.

3.2 Nominal transmission capacity for alternating current

- The transmission capacity is the technical limit for active power that can be continuously transmitted over a grid section with a starting point in an intact network. The trading capacity is agreed between the TSOs and is lower, typically by 5-10 %.
- For the calculations, dimensioning transmissions, load situations and generation situations for the grid shall be selected; according to Nordel's grid planning rules.
- The transmission capacity is determined on the basis that the grid must withstand the dimensioning fault (n-1) both on the interconnection and in the connected grids; see Nordel's grid planning rules. This applies regardless of limitations due to thermal conditions, voltage stability, dynamic stability or conditions in the underlying grid.
- The transmission capacity is stated as the highest value achieved during the year. The number of hours for which the transmission capacity is available shall be stated for each section.
- The limiting factor must always be stated for the technical limit.
- The transmission capacity is measured on the receiving end.

3.3 Overloading of components

COMPONENT LOADING ABOVE NOMINAL				
Component	**Denmark**	**Finland**	**Norway**	**Sweden**
Overhead line /cables	"one hour's" current with a wind of 1.6 m/sec [1)] / 150 % with cables. In the future this will be assessed individually.	Uses temperature depending on area	120 % for 15 min	Conductor temperature +20°C at 30°C air and wind of 1 m/sec
Transformers	130 %	150 % briefly	130 % with 0°C air	120 % for one hour.
End-point components	Does not normally limit the line	Nominal value	100 -> 120 % for up to 15 min	0

[1)] Operational possibility that is not brought into the calculation in the planning phase.
Series capacitors are dimensioned according to the IEC standard.

4 Grid planning for interconnections between the Nordel area and other areas

With the exception of West Denmark, the Nordel system is operated asynchronously with other electric power systems. Decisions on the establishment of new interconnections to and from the Nordel area have been formalised in the form of bilateral agreements. Such interconnections will nevertheless affect the entire Nordic electric power system, not just the TSOs that establish the new interconnection. It is therefore important that the planning of such interconnections is coordinated with the Nordic grid master plan. It is desirable that Nordel should take part in the planning work in a way that ensures that such expansion can be made clear to all of Nordel.

4.1 Planning new interconnections[2]

Appendix 2: Final report of Nordel's HVDC working group contains an approved overview report about new HVDC interconnections between Nordel and UCTE. A draft Nordel recommendation has been written on the basis of this report.

- The control systems for new HVDC interconnections should be adapted so that the risk of multiple commutation failures in the event of dimensioning fault, is minimised. It is assumed that the grid will be designed in accordance with the plans presented. There should be verification by means of simulator tests.

[2] Written in the light of draft Nordel recommendation.

- Maximum frequency-controlled emergency-power activation in the direction away from the Nordel system should correspond to the dimensioning outage in the Nordel system. In direction towards the Nordel system a greater activation can be accepted. Frequency-controlled step or ramp variation of the power is permitted when the frequency is below 49.5 Hz. The basic rule is that the instantaneous disturbance reserve is divided up equally between the HVDC interconnections. However, transfer can occur subject to prior agreement between the owners of the HVDC interconnections.
- Emergency power control (EPC) with the HVDC interconnections should not be concentrated electrically, due to the risk of tripping several HVDC interconnections simultaneously.

5 Planning code for planning the Nordic transmission system

The criteria are still deterministic, although probabilistic considerations have been taken into account. In the criteria, demands are made on disturbance consequences that are acceptable for various combinations of operating conditions and fault types. In principle, more serious consequences are acceptable for less common combinations of faults and operating conditions. This principle is illustrated with the following figure.

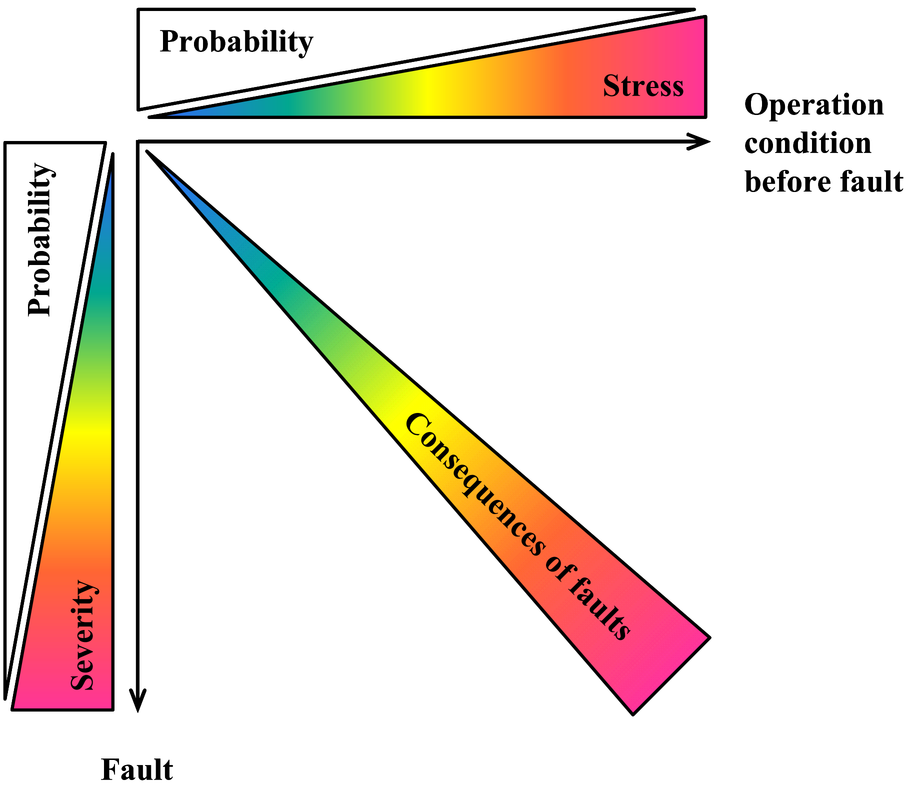
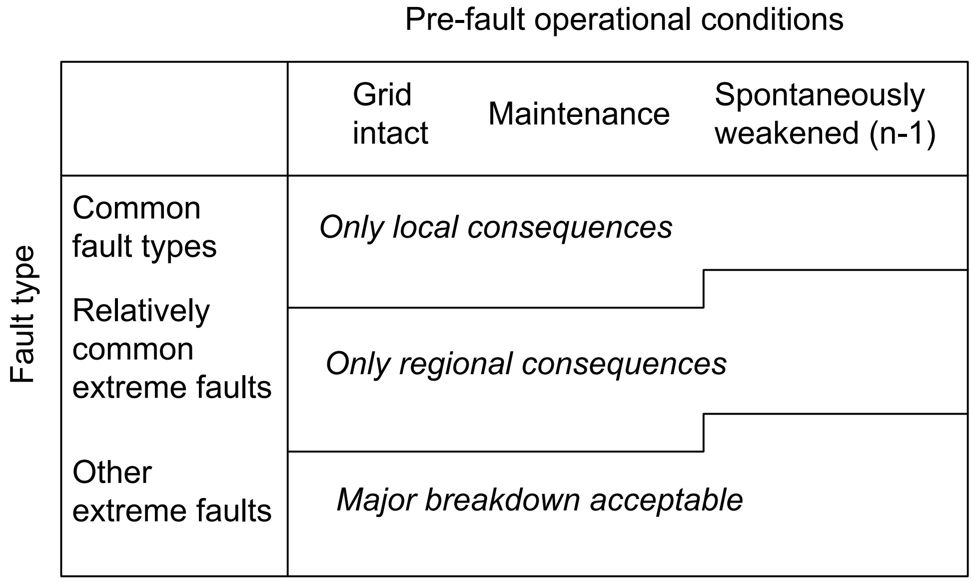


Figure **2.** *Illustration of the correlation between operation condition (including probability / stress of the condition), faults (including probability / severity of the faults) and acceptable consequences of faults.*

The main structure can be summarised in accordance with the table below.



The rules are intended for use in the planning of the Nordic main grid. They should also be able to serve as support in the operation of the grid.

5.1 Principles of the planning code

The rules shall be used for the joint, synchronised Nordic transmission grid. This concerns principally the main grid, mainly 220-400[3] kV, and the interconnecting links between the various countries. The rules should be used in the planning of the power system. The aim is that the operation and planning work should be based on the same reliability philosophy, and that the rules should also be able to serve as a guide at the operating stage. The rules do not cover local supply reliability and other local conditions in the grid.

In order to safeguard a certain minimum reliability level for the interconnected Nordic power system, certain minimum demands on reliability for the required transmission capacity have been defined through the planning rules. The demands have been given concrete form by a number of criteria, which must be met in grid design. The criteria are based on a balance between the probability of faults and their consequences, i.e. more serious consequences may be acceptable for faults with lower probability.

The grid strength defined through the rules is such that it will be possible to maintain the required transmission level if the grid is intact under varying generation and load situations. If transmission lines are out of operation, lower capacity will normally be accepted.

The required transmission capacity can be achieved by a number of measures affecting the construction of primary equipment, system protections and auxiliary systems, as well as disturbance reserves and other operational measures. In the case of more severe disturbances than those directly taken into account in the criteria, it is assumed that operational facilities are available in the power system for restoring operation.

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[3] In Norway nominal voltage is 420 kV

The rules are based on assessments, based on experience, of fault probabilities and availability of individual items of equipment. Future changes in the reliability of individual items of equipment or the introduction of new equipment may place special demands on grid design.

5.2 Planning criteria

5.2.1 Structure

Deterministic criteria are used in the planning of the grid. This means that a number of faults groups have been specified, against which the grid will be tested. The following are defined for every fault group

- prefault conditions, and
- acceptable post fault consequences

The criteria are summarised in the scheme in *Figure 3*, and in a list of fault groups, etc. in accordance with Chapter 5.5. The operating conditions before the fault, the fault types and consequences of various faults are described below.

5.2.2 Prefault operating conditions before the fault

The grid strength shall be studied for the following grid operating conditions.

Grid intact

All grid components that are of importance for the fault being studied are in operation.
For the grid studies, the dimensioning transmissions, load situations and generation situations for the grid shall be selected. As an example, for the surrounding grid it shall be possible to assume the transmission levels that correspond to the agreed capacities (normally in accordance with the Planning Code). Economically reasonable generation situations shall be assumed.

Grid not intact, scheduled work

A shunt or series component that is of importance for the studied fault shall be assumed to be out of operation for maintenance.
The point in time shall be selected on the basis of a suitable operating situation, e.g. with low transmission. The objective is to take into account in the planning the future need for maintenance, and to create sufficient flexibility for this purpose.

A shunt component is a component that belongs to fault group FG1, i.e. a generation unit or reactive shunt component (capacitor, etc.). A series component is a component that belongs to fault group FG2, i.e. transmission line, series capacitor, busbar, etc.

Grid not intact, unscheduled outage

A shunt or series component that is of importance for the studied fault shall be assumed to be out of operation due to a spontaneous fault event.

The point in time is assumed to be 15 minutes after the component failure. Generation and transmission have thus been adapted as far as possible with the disturbance reserves available. For the studied section of the grid, it is acceptable that the transmission has been reduced, provided that the needs of the consumers and other special transmission requirements can simultaneously be met.

5.2.3 Columns in the criteria scheme – Prefault conditions

In the criteria scheme (Chapter 5.4), five columns with different operating conditions have been defined as follows.

PC0 Grid intact
PC1 Grid not intact, scheduled maintenance
PC2 Grid not intact, spontaneous loss of a shunt component
PC3 Grid not intact, spontaneous loss of a series element
and three columns for even more serious conditions, with several components out of operation. Alternatively, the operating situation is not adapted, i.e. the time is less than 15 minutes after the initial fault.

5.2.4 Fault groups

The fault types for which the grid is to be tested are classified into five fault groups. The fault groups have been selected to ensure that the grid will have a certain strength. This will hopefully also cover other relatively common fault types that have not been specified. The individual fault types are described in more detail in Section 5.5. Fundamental comments are given below.

Primary relay protection is assumed to perform in the intended manner, unless a different function has been defined in the studied fault type.

The faults have been grouped with regard to their probability. Faults in FG1 and FG2 are the most frequent. Fault group FG3 comprises less probable single faults and special more common double faults. Fault groups FG4 and FG5 contain rare faults.

Three-phase busbar faults in FG3 shall principally be taken into account for stations, which are of significance to joint operation between countries.

The following shall apply to the fault combination of a line fault with loss of a thermal power unit in FG4. An economic assessment shall be made of whether it is justified to implement such measures in the unit and grid that the fault condition will be equivalent to those in fault group FG3.

5.2.5 Permissible consequences

Three levels of consequences are defined. The principal demands made are those that are of significance for the interconnected Nordic power system.

A. Stable operation, local consequences

Only local consequences are acceptable. Apart from the load shedding or tripping of generation that is necessary for eliminating the fault, limited amounts of loads and generation may be switched out by means of the system protections. After the fault, operational adaptation of the transmissions is acceptable.

It shall be possible to maintain stable operation as regards transient, dynamic and static stability for both frequency and voltage conditions, and no consequential tripping shall take place due to overloading of components. In addition, it is assumed that the voltages and frequency after the fault will be satisfactory for the consumers and power plants. Efforts shall be made to maintain joint operation also after the fault, and planned sectionalisation of the grid shall not normally be employed as a method for ensuring stability.

B. Controlled operation, regional consequences
The consequences shall be limited and further controlled operation shall be maintained for most of the system.

Controlled forced tripping of generation and load shedding may be carried out. Load shedding or forced generator tripping shall normally be confined to the region in which the fault has occurred. Minor grid breakdowns and grid sectionalisation are also acceptable provided that they are restricted to the region in which the fault has occurred. The term 'region' denotes parts of the national grid, which are confined by the main cross-sections in the national grid or by the interconnecting links (international tielines). In exceptional cases, major national disturbances may be permissible provided that they do not spread beyond the interconnecting links. However, subject to agreement, load shedding may be extended to other parts of the Nordic power system. This applies in particular to the use of system-wide system protections.

C. Instability and breakdown
Instability is acceptable. Grid sectionalisation and extensive breakdowns can take place in the Nordic system. However, the objective is to create a defined initial situation from which restoration can take place.

It is assumed that operational possibilities will be available for restoring operation to normal levels. It is also advisable to investigate at the planning stage whether simple measures can be applied to restrict the consequences in the event of very rare and difficult faults.

5.2.6 System protection scheme

The term system protection scheme denotes automatic control equipment that disconnects or otherwise controls generation, load or network components other than the faulty component. Disconnection may concern both individual components and a large number of components. The definition of system protection scheme is given in the System Operation Agreement appendix 1 and requirements for system protection in the System Operation Agreement appendix 2.

5.3 Other important aspects of system planning and design

5.3.1 Operational aspects

Future operational aspects shall be taken into account in the planning of the grid. Fundamental principles and criteria for planning and future operation must therefore be founded on the same basic ideas. The design includes both system design and the performance of individual objects.

The economic dimensioning of the grid means that consideration must be given to costs and need for flexibility at the operating stage.

It shall be possible to handle shutdowns of one or several system components in a manner, which is acceptable to operation.

At the operating stage, it shall be possible to distribute the disturbance reserves in an economical manner. The grid should therefore be designed so that transmission margins are available or that fault conditions will not lead to loss of necessary reserves.

Operating possibilities shall be available for handling major disturbances. This includes operating routines, equipment and training to enable both abnormal operation and restoration to normal operation to be handled.

5.3.2 Operational characteristics of generation plants

The units are assumed to have certain operational characteristics. These demands are i.e. regulated by the Connection Code.

The units shall have such tolerance to variations in voltage and frequency that it will be possible to handle the most common types of grid fault without the units being tripped or damaged. The units shall also have such control capability that they will be able to contribute towards the disturbance tolerance of the grid as active and reactive disturbance reserves.

5.3.3 Instructions

As a supplement to the planning criteria, instructions containing special national demands and 'user instructions' for the planners shall be drawn up. The instructions shall be prepared for each country, and shall then be co-ordinated between the countries.

The objective of the planning criteria is to achieve acceptable strength of the interconnected Nordic power system. Only a few demands are made on the supply security and local conditions. It is therefore natural to supplement the criteria with national planning requirements.

The structure of the criteria gives a large number of combinations of operating situations and faults that must be tested. In practice, only a few of them are dimensioning to the design of each individual section of the grid. Special comments should be made on these combinations, and instructions should be given on how calculations should be carried out.

Since several consequence levels have been introduced in the criteria, strict demands are made on knowledge of the nature of the power system and its behaviour in the event of disturbances. Experience and calculation methods must therefore be gathered and comments must be made on them.

5.4 Post fault performance table (Criteria Scheme)

<table>
<tr>
<td rowspan="4" colspan="3">Acceptable consequences
A Stable operation, local consequences and limited intervention of system protection
B Controlled operation, regional consequences
C Instability and breakdown
A/B Consequences in accordance with B for faults in previously weakened area, otherwise A.
B/C Aim should be to limit the consequences according to B but for all faults this cannot be fulfilled

[1] The operating situation has been adapted during 15 minutes after the fault by using the means available (disturbance reserves, etc.).</td>
<td colspan="7">Pre-Fault Conditions</td>
</tr>
<tr>
<td colspan="4">Normal operation</td>
<td>Alert-state operation</td>
<td>Disturbed operation</td>
<td>Emergency operation</td>
</tr>
<tr>
<td>Grid intact</td>
<td>Planned maintenance</td>
<td colspan="2">Spontaneous loss and adapted operation[1]</td>
<td rowspan="2">Exceeded transfer limits / insufficient reserves. Adapt operation by adjusting new transfer limits and / or activating reserves within max. 15 min.</td>
<td rowspan="2">Exceeded transfer limits and / or insufficient reserves</td>
<td rowspan="2">Exceeded transfer limits and / or insufficient reserves

Load shedding effected</td>
</tr>
<tr>
<td>No critical components out of operation

PC0</td>
<td>Shunt or series component out of operation

PC1</td>
<td>Shunt component out of operation

PC2</td>
<td>Series component out of operation

PC3</td>
</tr>
<tr>
<td rowspan="5">Fault groups</td>
<td rowspan="3">N-1 faults</td>
<td>Single fault that does not affect series components FG1</td>
<td rowspan="3">A</td>
<td rowspan="3">A</td>
<td rowspan="3">A</td>
<td>A</td>
<td rowspan="3">B/C</td>
<td rowspan="2">B/C</td>
<td>B/C</td>
</tr>
<tr>
<td>Single fault that affects series components FG2</td>
<td>A/B</td>
<td rowspan="4">C</td>
</tr>
<tr>
<td>Uncommon single faults and special combinations of two faults FG3</td>
<td>B</td>
<td rowspan="3">C</td>
</tr>
<tr>
<td rowspan="2">Serious faults</td>
<td>Other combinatios of two faults caused by the same event FG4</td>
<td>B</td>
<td>B</td>
<td>B</td>
<td rowspan="2">C</td>
<td rowspan="2">C</td>
</tr>
<tr>
<td>Other multiple faults FG5</td>
<td>C</td>
<td>C</td>
<td>C</td>
</tr>
</table>

Figure 3 Criteria Scheme to be used for grid planning

5.5 Fault groups

The faults for which the grid is to be tested are classified into five fault groups.

FG1 Common single faults that do not affect (transmission lines or other) series components

Definite loss of

- 1.1 Generation unit
- 1.2 Load block with associated transformer
- 1.3 Shunt component (capacitor, reactor)
- 1.4 DC pole (connected to adjacent system (e.g. Baltic Cable))

FG2 Common single faults that affect (transmission lines or other) series components

Definite loss, with or without initial single-phase permanent fault

- 2.1 Transmission line, one circuit
- 2.2 System transformer
- 2.3 Busbar
- 2.4 Other series component (series capacitor, etc.)
- 2.5 DC pole (Internal Nordic connection)

FG3 Less common single faults and special, more frequent combinations of two simultaneous faults

Definite loss with initial 2-phase or 3-phase fault

- 3.1 Transmission line, one circuit (without fast autoreclose)
- 3.2 Busbar[4]
- 3.3 Combination that includes equipment with unknown reliability.

FG4 Other combinations of two simultaneous faults with a common cause

Definite loss with initial 3-phase fault

- 4.1 Combination of line fault and loss of thermal power unit[5]
- 4.2 Double circuit transmission line
- 4.3 Stuck breaker pole or relay fault in the event of fault clearance
- 4.4 Two power station units
- 4.5 Station with sectionalising circuit breakers
- 4.6 DC bipole link
- 4.7 Two transmission lines along the same cleared path

FG5 Other multiple faults (two independent simultaneous faults, and three or more simultaneous faults)

- 5.1 Two independent simultaneous faults
- 5.2 Three or more simultaneous faults

---

[4] Considered principally for stations that are of importance to joint operation between countries

[5] Measures in the grid and on units assessed economically against grid consequences

APPENDIX 1: METHOD, MODELS AND TOOLS FOR SYSTEM ENGINEERING STUDIES

1 Methodology for system engineering studies

- Studies to evaluate the need to reinforce the grid
- The benefit values of alternative reinforcing measures
- Determining and describing preconditions
- Analysis of the technical properties with alternative solutions
- A technical/economic evaluation and prioritisation of these alternative solutions
- Choice of reinforcing measures

A method for this is shown in *Figure 4*. The method is described in more detail below.

1.1 Planning information and preconditions

The various preconditions that are fundamental for making analyses of the electric power system are described in *Figure 4*. Scenarios and basic assumptions are of particular importance (alternative developments that are important for the reinforcing need that is to be studied). This includes preconditions with regard to general load development, special load increases, production expansion, etc. When establishing models for carrying out the technical analyses it is important to consider operational situations that are of significance for the evaluation of limitations, capacity and reinforcing needs.

1.2 System reliability

The long-term planning of the electric power system must ensure the reliability of the system (security of supply). The international concepts for system reliability cover:

- system security, which covers necessary system services and grid capacity for the transport of these services.
- system adequacy, which covers sufficient production and grid capacity to meet demand.

The following concepts agree with the international definition of system sufficiency. The term “energy security” refers to the ability of the electric power system to deliver to consumers the desired amount of energy with a given quality. The term “power security” refers to the ability of the electric power system to deliver to consumers the desired amount of power with a given quality. A common expression for these two concepts is delivery security (or system sufficiency).

Internationally, security of supply is expressed with the concept of system reliability, where delivery security/system sufficiency is one part and system security is the other. System security is the ability of the electric power system to withstand sudden disturbances such as electrical short circuits or the unexpected disconnection of parts of the system. The concept includes dynamic conditions.

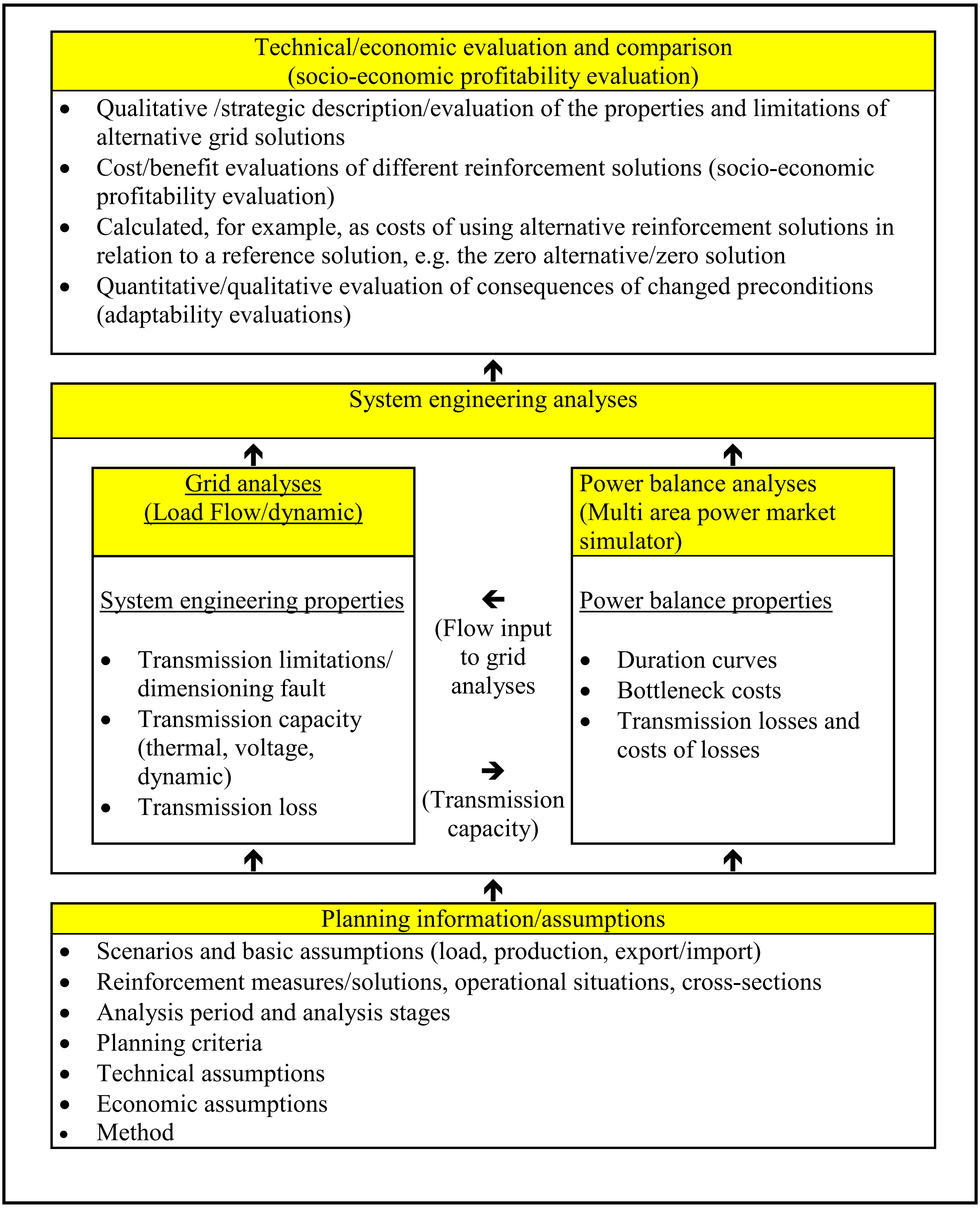

Figure 4 Procedure for carrying out a socio-economic profitability evaluation

1.3 System engineering analyses

System engineering analyses include grid analyses and power balance analyses:

- Grid analyses include the analysis of transmission limitations and transmission capacity (thermal, voltage and dynamic) for existing grids and alternative reinforcement solutions for relevant operational situations and scenarios. Information about energy flows in the grid, e.g. duration curves from power balance analyses will be important background regarding the need for transmission capacity in important cross-sections. The calculations are done with the load flow and dynamic simulation software and a relevant grid model.
- Power balance analyses include analysis of energy flows under the relevant scenarios. Among other things, duration curves are calculated for transmission between the individual joint load areas and bottleneck costs with limitations between these areas. The calculations are done with the multi-area power market simulator and a relevant grid model.

Duration curves are calculated without limitation between the relevant network areas, possibly without limitations between several/all areas.

Bottleneck costs are calculated with one fixed or several relevant capacity levels in the cross-section concerned, and without or with relevant capacities between the other areas. Relevant transmission capacities are obtained as a result of the grid analyses.

1.4 Technical/economic evaluation and comparison

Technical/economic comparison will include a summarising evaluation of the grid-related and power-balance-related properties of different grid reinforcement solutions in different scenarios.

Benefit value and cost evaluations (socio-economic profitability evaluations) will be important for evaluating alternative reinforcement measures, but more qualitative and strategic evaluations of alternative reinforcement solutions will have to be undertaken before a final decision to implement relevant reinforcement measures is made.

A socio-economic profitability evaluation can be done with various profitability evaluation methods. A method for calculating the net present value benefit of a reinforcement measure is described here.

The net present value is calculated as a capitalised and discounted value of all costs during the analysis period, stated as the benefit in relation to the reference solution (e.g. the zero solution[6]). For a measure to be socio-economically profitable, the following requirement must be met:

Net present value benefit (NNN) > 0

[6] The "zero solution" means the existing grid, i.e. with no measures taken to reinforce the grid (concrete reinforcement measures), or to utilise the grid more (e.g. system protection measures) in relation to existing grids and operational practice.

The net present value benefit is calculated on the basis of technical costs and system costs as follows:

$$NNN = \Delta I - \Delta D - \Delta M + \Delta F + \Delta T - \Delta A - \Delta S$$

(Δ means costs, cost/benefit effect of the measure compared with a reference solution, e.g. the zero solution.)

Cost components included are:

Technical costs

ΔI: Investment costs, possibly investment/reinvestment costs, etc. in relation to the corresponding costs of the reference solution.

ΔD: Operating and maintenance costs, i.e. o/m costs due to new measures or in relation to the corresponding costs of the reference solution.

ΔM: Environmental costs compared with the corresponding costs of the reference solution. Environmental costs are often difficult to quantify, and the environmental consequences are therefore often only evaluated qualitatively.

System costs

ΔF: Bottleneck costs, expressed as reduction (benefit) with respect to the bottleneck costs of the reference solution.

ΔT: Loss costs, expressed as the benefit compared with the costs of transmission losses for the reference solution.

ΔA: Outage costs compared with the corresponding costs of the reference solution.

ΔS: System costs compared with the corresponding costs of the reference solution.

Power/energy balance analyses and network analyses are carried out. The area subdivision used in the analyses is described.

2 Electrical engineering electric power system models

To carry out the analyses, a model of the Nordic electric power system is used which contains the transmission installations included in the system, e.g. transmission lines, transformers and generating plant. Underlying networks with corresponding components and connected consumption are also modelled. Analyses are done for relevant operational situations, i.e. with a relevant switching configuration in the grid and with correct production and consumption levels, so that transmissions and voltage levels are correct.

For this purpose the following load cases are created:
- High-load scenario with a five-year horizon.
- High-load scenario with a ten-year horizon.

2.1 Electrical engineering system analyses and tools

The practical analyses for determining, for example, the transmission capacity of the grid, are carried out by determining dimensioning operational situations and types of fault, limiting components (thermal) or limiting system properties (voltage collapse, dynamic instability), as well as loading of the grid until the limiting components are fully loaded or the limiting system properties are exceeded (voltage collapse, dynamic stability).

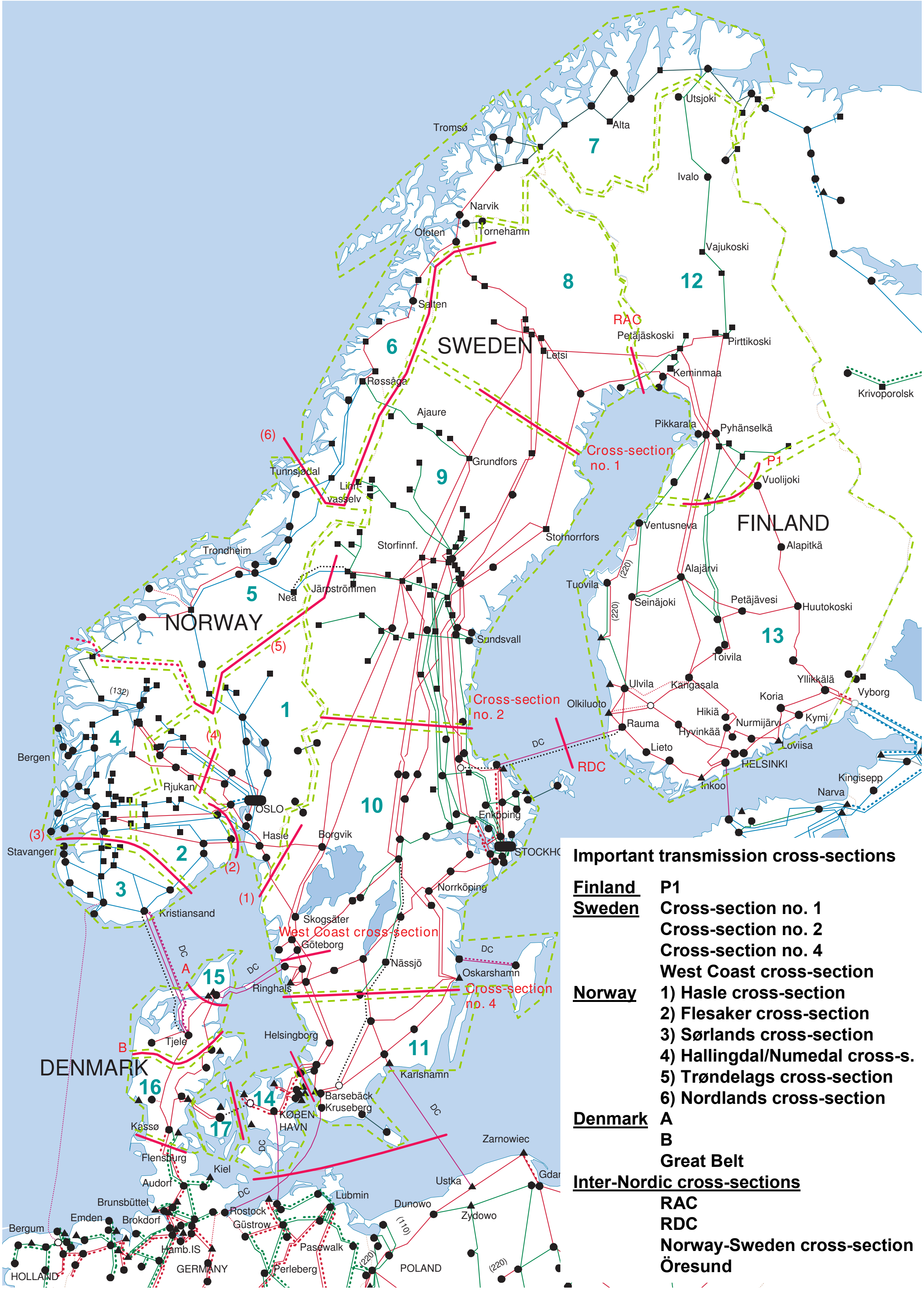

Figure 5 *Important transmission cross-sections in the Nordel area shown in relation to the area division (areas 1 – 17) for which power and energy analyses are made.*

2.2 Security of supply for energy and power

As well as analysing the capacity for transport on the market, it is important to determine whether there are sufficient resources in the generating plant to maintain security of supply in the Nordel area. This is done by analysing the probability of energy or power shortage. Where the energy supply is concerned, the focus is on dry years and extreme dry years for the hydropower system. Where power is concerned, the focus is on normal winter load and extreme winter load that occurs once every ten years.

There may be a need to develop a number of security-of-supply criteria, which determine the Nordel area's possible degree of self-supply in terms of power and energy.

APPENDIX 2: FINAL REPORT OF NORDEL'S HVDC WORKING GROUP FROM YEAR 1998

1 Background

The near future will see a rapid increase in the number of HVDC connections for transmission of power between the Nordel and UCTE systems. At present, total transmission capacity is almost 3000 MW, while current plans are for it to increase to about 5500 MW within the next few years.

The desire for such increase in the HVDC capacity springs primarily from commercial interests, powered by the idea within the EU of creating a single energy market, as well as the scope for joint operation of hydroelectric power generation in Nordel with thermal electricity production on the Continent. The prospect of an expansion of the existing main network is hampered by considerable public opposition to overhead lines.

The HVDC connections, having independent owners and representing uncoordinated interests, are in certain cases expected to draw so much from the Nordel system as to disrupt the stability of operations. With uncoordinated operation of the connections, there is a risk that a disturbance in the UCTE system could affect the dimensioning of the Nordel system.

The fast power control properties of the HVDC connections can contribute to improving the overall frequency quality of the system. Any production outage will affect system frequency. Depending on the extent of frequency deviations, various forms of emergency power will be activated. Current practice as regards emergency power in the Nordel system is described in Nordel's recommendation "Rekommandasjon for frekvens, tidsavvik, regulerstyrke og reserve", August 1996. The HVDC connections are included in both momentary operating disturbance reserve and in network protection control.

In consideration of the Nordel recommendation the power control properties of the HVDC connections may be used to improve the frequency quality in Nordel following disturbances of operation.

Nordel's HVDC working group has prepared two sub reports: "Sub report 1 prepared by Nordel's HVDC working group: Network disturbances" and "Sub report 2 prepared by Nordel's HVDC working group: System disturbances". This final report summarises the results from the two sub reports.

2 Objective

The objective of the work of the working group has been to illustrate:

- the impact of serious network disturbances on a system with several HVDC connections, which in electrical terms are close together.
- the importance of rapid power control response from the HVDC connections to frequency variation generated by disturbances during operation.

The studies have been undertaken for a future scenario, about 2002, assuming HVDC connections from Norway to both the Netherlands and Germany, as well as from Sweden to Poland. However, the plan is not for two of the Norwegian connections to be established until 2005.

3 Results and conclusion

The work of the group has resulted in recommendations, partly concerning the need for co-ordination of restart of HVDC connections following a network disturbance and partly concerning HVDC power control for frequency reserve.

The work has resulted in two sub reports, which have been considered by Nordel's System Committee; "Sub report 1 prepared by Nordel's HVDC working group: Network disturbances", Trapla 1997-10, 04.03.98 and "Sub report 2 prepared by Nordel's HVDC working group: System disturbances", Trapla 1997-42, 04.03.98.

3.1 Network disturbances

As far as network disturbances are concerned, the study focuses on power flow in the direction from UCTE to Nordel, since this is a "worst case" scenario, corresponding to inverter operation and low short-circuit power in Nordel. Only dimensioning network disturbances, for example busbar faults as described in Nordel's network dimensioning rules (1992 edition), are examined.

Commutation failure

Practical experience has shown that commutation failures caused by a network disturbance only occur concurrently on HVDC connections that in electrical terms are close together. For example, concurrent commutation failures have been seen on Kontek and Baltic Cable caused by an unsymmetrical network disturbance on Zealand, while other plants in Sweden and Norway continued operations as usual.

This study concentrates on the risk of repeated commutation failures, i.e. commutation failures during the restart of HVDC connections after a network disturbance. Only HVDC connections that are close together in electrical terms fail at the same time, e.g. Kontek, Baltic Cable and SwePol. This means that even with maximum power transmission to Nordel by all HVDC connections, the power that is lost immediately cannot exceed the sum of the connections affected.

There are no dimensioning faults that can cause commutation failure on all connections at the same time.

Possible action

The HVDC power that can be transmitted to a network area is highly dependent on the local short-circuit power Sk, e.g.:

- approx. 3000 MW at a short-circuit power of approx. 6 GVA, falling to
- approx. 2000 MW at a short-circuit power of approx. 4.5 GVA.

Increasing the short-circuit power by introducing various more or less expensive network measures could improve the situation, e.g.:

- increased network capacity,
- more production units in operation (rotating reserve) or
- synchronous condensers.

So far, work has shown that, as an alternative, it is highly advantageous to leave the control systems of the converter stations to handle the situation, e.g. through:

- gradual ramping-up from minimum power to the ordered level for a single connection in the affected area, or
- automatic shift-over from power control to current control on a single HVDC connection immediately after a network disturbance and in the case of commutation failure upon restart. This function is already available for some HVDC connections.

The expansion of the control systems on future HVDC connections to include such ”soft start” functionality presents a highly attractive solution, both technically and financially.

With a refined control system design, it will become feasible to increase the number of HVDC connections to an extent corresponding to the number of connections examined in the present study, trigging substantial reinforcements in the network.

Damping
Substantial improvements can be achieved in the damping of power oscillations in the network around known “bottlenecks”, e.g. the Hasle cross-section through Southern Norway and Central Sweden exploiting the damping function of the HVDC connections in the right way.

However, general guidelines for the setting of the HVDC connections’ damping control function have not been determined.

3.2 System disturbances

Dimensioning outages and in a few cases outages larger than the dimensioning outage have been considered. As defined in Nordel’s network dimensioning rules (1996 edition), the dimensioning outage is 1200 MW.

Focus is primarily on the first few seconds following the disturbance, a time when the conventional and slower power control of the generators is not particularly effective, but when the HVDC connections have their strength. Figure 6 shows the typical development in frequency following a production outage and illustrates the terms ”minimum temporary frequency” and “stationary frequency”.

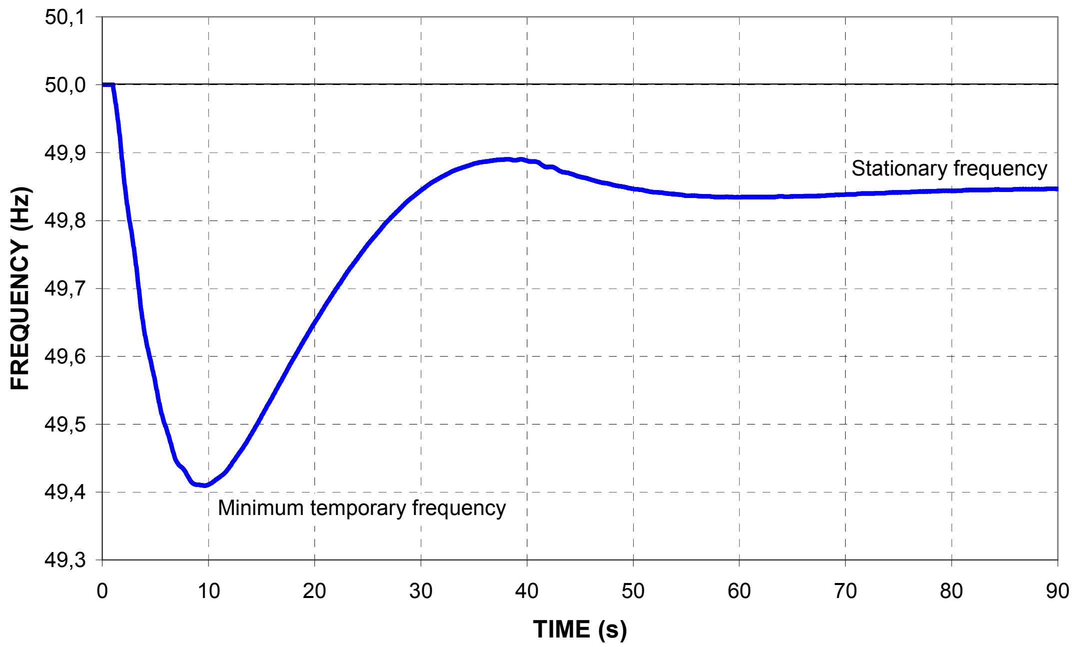

Figure 6 Development in frequency in Nordel following production outage

The power systems' frequency response within the first few seconds of the disturbance is improved markedly with HVDC emergency power control, reducing the minimum temporary frequency drop. The fast power control systems of the HVDC connections ensure efficient HVDC power control before regulation by the power control systems of the turbines.

The working group has identified the requirements that must be made to the power control of the HVDC connections with account being taken of Nordel's recommendations.

The following types of frequency-dependent emergency power control systems are recommended:

- HVDC droop control of up to, e.g., of 1000 MW/Hz in total as a momentary operating disturbance reserve (frequency control).
- HVDC emergency power in steps or ramps of up to 1200 MW in total as network protection control (EPC, Emergency Power Control).

<u>Momentary operating disturbance reserve</u>
HVDC frequency control (droop control) is activated in the frequency range between 49.9 and 49.5 Hz.

<u>Network protection control</u>
EPC, that is HVDC emergency power in steps or ramps, is activated when frequency drops below 49.5 Hz. It is recommended that a combination of frequency control and EPC should be used when the HVDC connections are used for network control, that is in the range below 49.5 Hz. During EPC, the frequency control should thus remain active. In this way, the ability of the EPC to quickly restore frequency to the desired level is used, while the frequency control ensures fast stabilisation of frequency.

Both the power response of the frequency control and the steps of the EPC should be determined on the basis of the current operating situation of the electricity system and with account being taken of the HVDC connections actually in operation.

The frequency response/droop of the HVDC connections within each local area can be set in relation to the currently phased-in MVA (S) and the load to ensure compliance with the minimum requirements for frequency control in the area.

The extent of EPC for each area can be set in relation to the current rotating reserve.

In situations where the Nordel HVDC connections are to supply emergency power to the UCTE system, the control parameters of the HVDC connections must be co-ordinated to ensure that the supplied emergency power does not exceed the dimensioning production outage of 1200 MW for Nordel.

In situations where the Nordel HVDC connections are to receive emergency power from the UCTE system, the control parameters of the HVDC connections do not need to be co-ordinated, if the recommended combination of static control and stepping-up or ramping-up of emergency power is used. This control principle ensures effective frequency control while preventing overcontrol.

4 Conclusion

The working group considers its task to be completed.

The following documents have been included in this chapter:

Document	*Status*
The System Operation Agreement 2006	*Binding agreement*

The following national documents deal with the Operational Code:

Document	*Status*

The TSOs in Scandinavia and Finland have entered into a System Operation Agreement. The System Operation Agreement contains rules for the operation of the interconnected Nordic electric power system, and is set out in this section. This is translation, the original one is in Swedish language.

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AGREEMENT (TRANSLATION) REGARDING OPERATION OF THE INTERCONNECTED NORDIC POWER SYSTEM (SYSTEM OPERATION AGREEMENT)

§ 1 The Parties etc

- Energinet.dk (Energinet.dk) corporate registration no. 28 98 06 71
- Fingrid Oyj (Fingrid) Business Identity Code 1072894-3
- Statnett SF (Statnett) corporate registration no. 962 986 633
- Affärsverket svenska kraftnät (Svenska Kraftnät)
  corporate registration no. 202100-4284

The terms and concepts occurring in this System Operation Agreement (the Agreement) and its appendices are defined in Appendix 1.

§ 2 Background

The *subsystems* of Norway, Sweden, Finland and Eastern Denmark are synchronously interconnected, forming the so called *synchronous system*. The *subsystem* of Western Denmark is connected to Norway and Sweden using DC interconnectors. The *synchronous system* and the *subsystem* of Western Denmark jointly constitute the *interconnected Nordic power system*.

The supervisory authorities of Denmark, Finland, Norway and Sweden have appointed special *system operators* who are comprehensively responsible for the satisfactory operation of each *subsystem*. These *system operators* are Energinet.dk for the Danish *subsystem*, including Bornholm, Fingrid for the Finnish *subsystem*, Statnett for the Norwegian *subsystem* and Svenska Kraftnät for the Swedish *subsystem*. Åland is not covered by this Agreement.

The background to entering into this Agreement is that operation of the *interconnected Nordic power system* entails operational collaboration and co-ordination taking place between the *system operators*. Effective collaboration between these will provide the technical prerequisites for trading in power on an open electricity market.
The Agreement and its Appendices regulate the operational collaboration between the *Parties*. Several of the Agreement's provisions are based upon recommendations issued by Nordel.

§ 3 Objective

The objective of the Agreement is to make use of the advantages arising from the interconnected operation of the Nordic power system. The *Parties* shall thus jointly uphold the interconnected operation of the Nordic power system on a satisfactory level of reliability and quality.

The *Parties* shall jointly uphold a supply quality that is appropriate to joint system operation, e.g. frequency, *time deviation*, system oscillations etc.

The *Parties* shall jointly operate the *interconnected Nordic power system* in a manner which promotes the efficient utilization of existing resources and power trading on the Nordic electricity market, as well as on an additional potential international market. The Agreement specifies in detail the commitments that the *Parties* undertake to honour during their operational collaboration.

The *Parties* are agreed that agreements regarding the operation of the *interconnected Nordic power system* shall only be entered into between the *system operators* concerned.

It is the *Parties'* intention that, as long as *transmission facilities* between the *subsystems* are in operation, there shall exist an agreement between the *Parties* regulating their operational collaboration, rights and commitments vis-à-vis system operation issues

§ 4 Appendices

The following Appendices are attached to this Agreement.

Appendix	Content
1	Definitions
2	Operational security standards
3	Balance regulation standards
4	Exchanging information
5	System protection
6	System services
7.1	Joint operation between Norway - Sweden
7.2	Joint operation between Sweden - Finland
7.3	Joint operation between Norway - Finland - Sweden (Arctic Scandinavia)
7.4	Joint operation between Norway - Western Denmark
7.5	Joint operation between Sweden - Western Denmark
7.6	Joint operation between Sweden - Eastern Denmark
7.7	Joint triangular operation between the Norwegian, Swedish and Western Danish subsystems.
8	Management of transmission limitations between subsystems.
9	Power shortages
10	The Nordel system's joint operation with other systems

The Appendices constitute an integral part of the Agreement.

In the event of any variance between the contents of the Appendices and what is set forth in this, the main part of the Agreement, what is set forth in the main part shall take precedence.

§ 5 Decisions etc concerning own subsystems

The *Parties* will make their own decisions regarding the principles applicable to the *system security* of their own *subsystems*.

The *Parties* agree, however, when taking such decisions, to comply with the intentions and principles of the Agreement as far as is possible and appropriate.

The *Parties* are individually responsible for formulating their own agreements concerning system operation collaboration between their own *subsystems* and *subsystems* outside of the *interconnected Nordic power system*, with which there are physical transmission links, in such a way that these do not contravene the intentions of, or prevent compliance with, the Agreement.

It is the intention of the *Parties*, as far as is possible within the legal framework provided (terms and conditions of concessions etc) to co-ordinate the terms and conditions of such agreements with the provisions of this Agreement.

Each respective *Party* shall enter into such agreements with companies within its own *subsystem* as are necessary to comply with the Agreement.

Unless otherwise agreed, the *Parties* shall be responsible for ensuring that measures taken within their own *subsystems,* which impact upon the operation of the system, shall not burden the other *subsystems*.

§ 6 Operational security standards

The *Parties* shall, in the day-to-day operation of the system and in their operational collaboration with other *Parties*, comply with the standards set forth in Appendices 2 and 3.

§ 7 Operational terms and conditions for the links between the subsystems

7.1 Transmission facilities

The *transmission facilities* linking the *subsystems* are accounted for in the following Appendices.

Appendix 7.1 Norway - Sweden
Appendix 7.2 Sweden - Finland
Appendix 7.3 Norway - Finland - Sweden (Arctic Scandinavia)
Appendix 7.4 Norway - Western Denmark
Appendix 7.5 Sweden - Western Denmark
Appendix 7.6 Sweden - Eastern Denmark
Appendix 7.7 Norway - Sweden - Western Denmark
(subsystems in triangular operation)

The *Parties* are responsible, as and when required, for detailed *operating instructions* being drawn up for the links listed in the mentioned Appendices within their own *subsystems*. In parts where such *operating instructions* have a bearing upon the joint system operation, they are to be co-ordinated with the companies and *Parties* concerned.

7.2 Transmission capacity

The *transmission capacity* of the links between the *subsystems* shall be bilaterally determined on a routine basis by the *Parties* concerned. Decisions shall normally be based on the *operational security standards* set out in Appendix 2 and on such current technical and operative factors as are of significance to the *transmission capacity*. The *Parties* are individually responsible for assessing these circumstances within their own *subsystems* and will decide on the necessary measures.

The *Parties* agree to reserve a *regulating margin* between the *transmission* and *trading capacities* of the links. The *regulating margin* shall normally have the values specified in Appendices 7.1 -7.7.

7.3 Special operational terms and conditions

In certain cases, special rules are applied as regards using the *transmission capacity* of the links. Detailed terms and conditions, together with the companies concerned, are specified in the respective Appendices 7.1-7.7.

7.4 Transmission losses

Issues concerning transmission losses are governed by separate agreements – settlement agreements.

A *Party* shall not be responsible for transmission losses arising within another *Party's subsystem* in any operational situation, unless otherwise agreed.

The *settlement points* are specified in Appendices 7.1-7.6.

7.5 Voltage regulation

Voltage regulation in the *subsystems* shall be conducted in such a way that the *operational security standards* specified in 6 § are upheld and in such a way that the reactive flow of power between the *subsystems* does not entail operational problems. The *Parties'* rights and liabilities regarding reactive power flows on the AC interconnectors are limited to what corresponds, calculation-wise, to zero exchange at the national border, based on values measured at the terminals of the links.

7.6 System protection

System protection can be used to increase the *transmission capacity* and/or *system security* between and within the *subsystems*. The settings and operational status of *system protection* shall be decided upon and monitored by the respective *Party*. In cases when *system protection* has a bearing on two or more *subsystems*, co-ordination and communication of the operating status shall take place between the *Parties* concerned. The requirements relating to *system protection* are set out in Appendix 2. The forms of *system protection* used are set out in Appendix 5.

7.7 Relay protection and fault analysis

The *Parties* shall co-ordinate supportive data and plans for setting functional values for the relay protection of such *transmission facilities*. Following *operational disturbances*, information from registration equipment shall be exchanged between the *Parties* concerned to the extent necessary to enable investigation of the course of events.

§ 8 Operational planning

The *Parties* shall, as far as is possible, bilaterally co-ordinate operational outages and other measures which each and everyone of them has control over and which impact upon the joint system operation. In the event that *operational disturbances* and other measures occur during the *operational phase* and which have to be carried out at short notice, with no time for co-ordination, the *Parties* concerned shall be informed as quickly as possible.

Appendices 7.1- 7.6 contain certain rules regarding the co-ordination of operational outages on the respective links between the *subsystems*.

§ 9 System services

The *Parties* shall comply with the *operational security standards* specified in § 6 by ensuring the availability of *system services* within their own *subsystems*. When this is possible, the *Parties* can co-ordinate and exchange *system services* with each other. During the exchange of such *system services*, the pricing shall be based on the costs incurred by the respective *Party* when obtaining access to and utilizing the *system services* within its own *subsystem*.

The *Parties* shall work towards harmonisation of the terms and conditions in order to gain access to *system services* from companies within the respective *subsystem*.

System services are described in Appendix 6.

§ 10 Managing transmission limitations between the subsystems

The *Parties* shall be bilaterally responsible for transmissions on the respective links between the *subsystems* not exceeding the set *transmission capacity*. If a limit is exceeded, this shall be rectified within 15 minutes.

The *Parties* shall bilaterally co-ordinate terms and conditions and management routines in order to be able, as and when required, to restrict the commercial players' utilization of the links in cases when *transmission capacities* need to be reduced. The separate terms and conditions that apply, as and when appropriate, to each respective link are set out in Appendices 7.1 - 7.7. The *Parties* shall uphold the commercial players' planned trading, by means of *counter trading,* to the extent set out in Appendix 8.

It is incumbent upon the *Parties* to manage, within their own *subsystems*, such transmission problems that cannot be solved by restricting the commercial players' utilization of the links. The *Parties* are further responsible for implementing the necessary regulation on their own sides of the links, and for the costs thus arising, unless otherwise agreed between the *Parties* concerned.

§ 11 Managing operational disturbances

In the case of all *operational disturbances*, *normal state* shall be resumed without undue delay. The *Parties* shall assist one another in minimising the consequences of any *disturbances* that arise.

In the case of disturbances arising within its own *subsystem*, the affected *Party* will be responsible, at its own expense, for remedial measures. Whenever it is appropriate to carry out remedial measures in another *subsystem*, the affected *Party* shall be responsible for the costs of the agreed measures. For disturbances on a link between the *subsystems*, the *Parties* concerned shall, at their own expense, be responsible for the necessary measures on their own side of the link, unless otherwise agreed.

In the case of activation of the joint *frequency controlled disturbance reserve*, compensation shall normally be rendered via the settlement of *balance power*.

The *Parties* shall promptly inform one another of *system security* risks or disturbances arising.

§ 12 Balance regulation

Each *subsystem* is responsible for planning itself into balance hour by hour, as well as for upholding its own balance during the hour of operation.

The *Parties* shall collaborate towards minimising the cost of *balance regulation* by utilizing, to the greatest extent possible, one another's regulation resources when this is technically and financially appropriate.

The *balance regulation* of the Nordic system is divided up into two *balance areas*. One of these *balance areas* is the *synchronous system* while the other *balance area* is Western Denmark.

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 system*.

The *balance regulation* of each *subsystem* within the *interconnected Nordic synchronous power system* shall be carried out in accordance with the principles set out in Appendix 3.

The basis of the *interconnected Nordic synchronous power system's balance regulation* is that regulation is carried out in respect of frequency. Regulation work is apportioned in accordance with the requirement for *frequency response* and a joint Nordic merit order *regulation list*. The entire Nordic power system shall constitute a single market for *regulation power*. In the event of *bottlenecks*, the *regulation market* can be split up.

The *Parties* shall pay attention to regulation problems within the hour of operation and especially at hour changes. Major changes to *exchange plans* should be managed via agreements concerning transitions.

§ 13 Power exchanges

13.1 Hourly exchange plans

Parties with adjacent *subsystems* shall jointly set routines for notifying hourly *exchange plans* and *trading plans* among the *subsystems*. Whenever transmission capacity is made available for other purposes than power trading, the relevant plans shall be bilaterally reported to each *player* individually. Trading must be reportable as a net trade between each *subsystem*.

13.2 Supportive power

Exchanges of *supportive power* between *Parties* with adjacent *subsystems* may be carried out in order to achieve efficient operation of the system. Such exchanges can come about as and when required during *normal state*, during *counter trading* or during *operational disturbances*. *Supportive power* can be agreed upon in advance, as well as commenced and terminated during the current hour of operation.

The principles for pricing *supportive power* are set out in Appendix 3.

13.3 Balance power

Balance power between the *subsystems* is calculated during settlement as the difference between the measured exchange of power and the sum of all forms of agreed exchange, including such exchanges as have been agreed between the *Parties*.

More detailed rules for managing and pricing *balance power* are set out in Appendix 3.

§ 14 Settlement

Settlement shall be based on the principles set out in § 12 - 13 for *balance regulation* and exchanges of power.

All settlement of exchanges of power between the *subsystems* shall take place at the *settlement points* specified in Appendices 7.1 - 7.6.

The settlement procedure is regulated bilaterally in separate agreements, settlement agreements, between the *Parties* concerned.

§ 15 Power shortages

When there is a risk of *power shortages*, the power trade within the power exchange area shall be given the opportunity, through price formation, to distribute risks and costs between the electricity market *players*. The *Parties* shall, as far as is possible and reasonable, work towards upholding such power trading and allocations of production capacity, which they do not contractually have the right to discontinue.

In the event of anticipated *power shortages* in one or more *subsystems*, the *Parties* shall collaborate in such a way that the resources available within the *interconnected Nordic power system* are utilized in order to minimise the extent of compulsory *load shedding*.

Acute situations such as general *power shortages* or *power shortages* resulting from *operational disturbances* on networks, or *bottleneck situations* when compulsory *load shedding* has to be carried out, are to be managed in accordance with Appendix 9.

System security shall be maintained on the level specified in Appendices 2 and 3 so that *dimensioning faults* do not lead to extensive follow-on disturbances in the *interconnected Nordic power system*.

§ 16 Exchanging information

Appendix 4 specifies the information that shall be exchanged between the *Parties* for system operation requirements.

If the information that the *Parties* are mutually exchanging has not been made public in the country the information relates to, the *Parties* pledge to keep this information confidential, as far as possible, in accordance with the legislation in force in the respective country.

§ 17 Liability

The *Parties* will only be liable to one another for damage resulting from gross negligence or malice aforethought.

None of the *Parties* will be able to hold any of the other *Parties* liable for lost revenues, consequential losses or other indirect losses, unless such damage has been caused by gross negligence or malice aforethought.

§ 18 Disputes

Should a dispute arise in connection with this Agreement, the *Parties* shall initially attempt to resolve their conflict through negotiation. If this does not succeed, the dispute shall, under Swedish law, conclusively be settled by arbitration in accordance with the Rules of the Arbitration Institute of the Stockholm Chamber of Commerce. The arbitration procedure shall take place in Stockholm.

§ 19 Alterations and supplements

Alterations and supplements to this Agreement shall, in order to be legally valid, be drawn up in writing and signed by all the *Parties*.

Appendices to this Agreement can be added to on a rolling basis. In doing so, Appendices which relate to all the *Parties* shall be updated jointly and approved by all the *Parties*. Appendices which deal with individual links shall be updated by the *Parties* that are affected by the Appendix in question. Any and all changes to Appendices shall be documented in writing and communicated to the *Parties*.

In the event of alterations to Appendices, the Appendices in question shall, by at the latest one month after the alteration has been made, be revised and sent out to all the *Parties*. An annual review of the Agreement shall be carried out in order to deal with any contractual revisions.

§ 20 Transfer

This Agreement may be transferred to another company which has been appointed as the *system operator* of a *subsystem* by the authorities of a country. Other transfers may not, wholly or in part, take place without the written consent of the other *Parties*.

In the event of the transfer of the *system responsibility* to another company, the *Parties* will be responsible for transferring their contractual commitments under this Agreement to the new *system operator*.

§ 21 Validity etc

This Agreement will come into force once it has been signed by all the *Parties* and will remain in force until further notice. The Agreement, which will apply from xx xx 2006, is conditional upon each respective *Party* receiving the necessary Board/Authority approvals.

If a *Party* deems the terms and conditions of this Agreement to entail unreasonable or inappropriate consequences, then this *Party* will be able to request, in writing, from the other *Parties* that negotiations be entered into as soon as possible with the aim of bringing about appropriate changes to the Agreement. Equivalent negotiations can also be entered into if the pre-conditions for the Agreement change significantly due to altered legislation or a decision made by an authority, or due to physical changes being made to the *interconnected Nordic power system*.

If a *Party* requests renegotiation, the other *Parties* will be obligated to actively take part in such negotiations within one month of receiving such a request.

If renegotiations do not, within six months of the request for renegotiation being made, lead to agreement being reached as regards such changes to the Agreement that the *Party* deems satisfactory, the *Party* shall have the right to terminate the Agreement. Termination, which must be in writing, shall occur by at the latest two weeks from the expiration of the renegotiation deadline. If such termination occurs, the Agreement shall be deemed to have ceased to be valid in respect of the terminating *Party*, once a period of six months has elapsed from the time when the notice of termination was communicated to all the other *Parties*.

This Agreement replaces the previous agreement dated 1 April 2004.
This Agreement has been drawn up and signed in four (4) identical copies, of which the *Parties* have received one copy each.

Fredericia 2006- -	Helsinki 2006- -
Energinet.dk	Fingrid Oyj
Peder Ø. Andreasen	Timo Toivonen
Oslo 2006- -	Stockholm 2006- -
Statnett SF	Affärsverket Svenska Kraftnät
Odd Håkon Hoelsæter	Jan Magnusson

DEFINITIONS

Terms defined in this Appendix are written in italics in the Agreement and its Appendices.

Most of the terms are Nordic and are not used in Continental Europe. Individual general terms correspond to terms used within UCTE. Terms concerning the capacity of the links between the subsystems are comparable to the corresponding terms within ETSO.

The **active reserve** is divided into *automatic active reserve* and *manual active reserve*.

Adjustment state is a transition from alert state to normal state, characterised in that consumption, production and transmissions in the network are adjusted so that the network can manage a (new) dimensioning fault. The adjustment takes place in 15 minutes from a fault which has involved the disconnection of components. See also *operational states*.

Alert state is an operational state which entails that all consumption is being met and that the frequency, voltage or transmissions are within acceptable limits. The reserve requirements are not fulfilled and faults in network components or in production components will lead to *disturbed state* or *emergency state*. Also see *operational states*.

Annual consumption is the sum of electricity production and net imports in a *subsystem*. Electricity production is the net production in a power plant, i.e. exclusive of the power plant's own consumption of electricity for electricity production.

An **area** is a part of the power system within a *subsystem*; an area can potentially comprise an entire *subsystem*. An area is bordered by *transmission cross-sections* in the national subsystems or by *cross-border links*.

Area prices are *Elspot prices* within an *Elspot area*.

The **automatic active reserve** is the active reserve which is automatically activated during the momentary operating situation. It is divided into *frequency controlled normal operation reserve*, *frequency controlled disturbance reserve* and *voltage controlled disturbance reserve*.

Balance areas are areas of the power system where there is continuous regulation in order to maintain the frequency and a physical balance in relation to adjacent areas. In the Nordic area, the *synchronous system* and Western Denmark are separate *balance areas*.

Balance power is the difference between the planned and measured transmissions between the *subsystems*.

Balance regulation is regulation in order to maintain the frequency and *time deviation* in accordance with the set quality requirements. Regulation is also carried out for network reasons.

A **bottleneck** is a capacity limitation on the *transmission network*. On the Elspot market, attention is paid to *bottlenecks* between the *Elspot areas*. During *operational planning* and *monitoring and control,* attention is paid to all physical *bottlenecks*.

Counter trading is the purchasing of upward regulation and the sale of downward regulation, on each side of a *bottleneck,* which the *system operators* carry out in order to maintain or increase the *trading capacity* of *Elspot trading* between two *Elspot areas,* or in order to eliminate a *bottleneck* during the *day of operation*.

Critical power shortage occurs during the hour of operation when consumption has to be reduced/disconnected without commercial agreements about this.

A **cross-border link** is a link between two *subsystems* including connecting line feeders on both sides of the link. For HVDC links, only the DC facility at stations on both sides of the link is included in the cross-border link.

The **day of operation** is the calendar day around the momentary operational situation.

A **deficit area** is a *subsystem* whose balance is negative, i.e. that power is physically flowing into the *subsystem* physically measured on the *cross-border links* between the *Parties*.

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.

Disturbed state is an operational state which entails that all consumption is being met, but that the frequency, voltage or transmissions are not within acceptable limits and that *normal state* cannot be achieved in 15 minutes. Also see *operational states*.

Elbas trading is power trading in Elbas at Nord Pool Spot. *Elbas trading* can occur in Sweden, Finland and Eastern Denmark prior to and during the *day of operation* after *Elspot trading* has finished.

Elspot areas are the areas of the Elspot market which the *interconnected Nordic power system* is divided into in order to deal with potential capacity limitations (*bottlenecks*) on the *transmission network*. Potential *bottlenecks* give rise to different *Elspot prices* in *Elspot areas*. In Finland, Sweden, Western Denmark and Eastern Denmark, the *Elspot areas* correspond to the *subsystems*.
In Norway, there are several *Elspot areas* within the *subsystem*.

Elspot prices are prices in *Elspot trading* within an *Elspot area*.

Elspot trading is power trading on the spot market of Nord Pool Spot. *Elspot trading* can occur prior to the *day of operation* in all *subsystems*.

Emergency power is power regulation on HVDC links activated by automatic systems on both sides of the respective HVDC link.

Emergency state is an operational state entailing that compulsory load shedding has been applied and that production shedding and network divisions may occur. Also see *operational states.*

ETSO (European Transmission System Operators) is an organisation for *system operators in Europe.*

An **exchange plan** is a plan for the total agreed active power to be exchanged hour by hour between two *subsystems*. This can be a plan for a whole calendar day or a number of hours (energy plan) and, whenever *supportive power* occurs during a part of the hour, also a momentary plan during the hour (power plan).

The **fast active counter trading reserve** is the *manual active reserve* for carrying out *counter trading*.

The **fast active disturbance reserve** is 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.). Restores the *frequency controlled disturbance reserve*.

The **fast active forecast reserve** is the *manual active reserve* for regulation of forecasting errors for consumption and production.

Faults are events which occur in the power system and lead to a reduced capacity or loss of a line, bus bar, transformer, production units or consumption. A fault causes an *operational disturbance* in the power system.

The **frequency controlled disturbance reserve** is the momentarily available active power available for frequency regulation in the range of 49.9 – 49.5 Hz and which is activated automatically by the system frequency. Previously called the momentary disturbance reserve.

The **frequency controlled normal operation reserve** is the momentarily available active power available for frequency regulation in the range of 49.9 – 50.1 Hz and which is activated automatically by the system frequency. Previously called the frequency regulation reserve.

The **frequency response** is the change ability in production dependent on the frequency of the network (MW/Hz).

The **interconnected Nordic power system** is the interconnected *subsystems* of Finland, Norway, Sweden, Western Denmark and Eastern Denmark for which the Nordic *system operators* have joint *system responsibility*.

Load following entails *players* with major production changes reporting their production plans with a time resolution of less than 1 hour.

Load shedding is the automatic or manual disconnection of consumption.

The **manual active reserve** is the active reserve which is activated manually during the momentary operational situation. This is divided into the *fast active forecast reserve,* the *fast active disturbance reserve,* the *fast active counter trading reserve* and the *slow active disturbance reserve*.

Manual emergency power is power regulation on the HVDC links which is activated manually.

A **momentary area control error** is the disparity (in MW) between the sum of the measured power and the sum of the agreed *exchange plan* on the links between the *subsystems* plus frequency correction, which is the *subsystem's* momentary *frequency response* multiplied by the deviation in the frequency away from 50 Hz. Also called the momentary imbalance.

N-1 criteria are a way of expressing a level of *system security* entailing that a power system can withstand the loss of an individual principal component (production unit, line, transformer, bus bar, consumption etc.). Correspondingly, n-2 entails two individual principal components being lost.

Network collapse is an operational state that entails that all loads in one or more areas are shed and that production shedding and network divisions can occur. Also see *operational states*.

Normal state is an operational state entailing that all consumption requirements are being met, that frequency, voltage and transmission lie within their limits and that reserve requirements are being met. The power system is prepared to deal with *dimensioning faults*. Also see *operational states*.

An **operational disturbance** is a disturbance to the power system. This can be the loss of a line, a bus bar, a transformer, a production unit or consumption.

An **operational instruction** is an instruction given to the control rooms of the *system operators* concerning how they are to behave in an operational situation.

Operational monitoring and control is the monitoring and control of the operation of the power system carried out by the control rooms.

The **operational phase** is the time from the momentary operational situation and the rest of the *day of operation* when trade on the Elspot market has already been determined.

Operational planning is the *system operators'* planning of the operation of the power system.

The **operational reserve** is the reserve that the *system operators* have access to during the *day of operation*. It is divided into the *active reserve* and the *reactive reserve*.

Operational security standards are criteria which the *system operators* use when conducting *operational planning* in order to uphold the reliable operation of the power system.

The **operational states** are *normal state, alert state, disturbed state, emergency state and network collapse*. See also *adjustment state* and *restoration*. These were earlier referred to as the power system's operational states. See Figure 1.

Outage planning is the planning done by each individual *system operator,* as well as between the *system operators,* of the necessary outages affecting *transmission capacities* between the *subsystems*.

A **Party** is one of the *system operators* entering into this Agreement regarding operation of the *interconnected Nordic power system*. The *Parties* are Energinet.dk, Fingrid, Statnett and Svenska Kraftnät.

The **peak load resource** is an *active reserve* which normally has a long readiness time. In the event of anticipated peak loads, the readiness time is reduced so that the *peak load resource* can be used prior to the *day of operation* on the Elspot market or during the *day of operation* on the *regulation market*.

The **planning phase** is the time until which bids submitted for the next calendar day's *Elspot trading* on the power exchange can no longer be changed.

A **Player** is a physical or legal persona active on the physical electricity market in the form of bilateral trading with other *players*, *Elspot trading*, *Elbas trading* or trading on other existing marketplaces.

The **power operation manager** is the person who has obtained, from the holder, the task of being responsible for managing the electrical facility.

The **power operation responsibility boundary** is the boundary of a well-defined area in the *transmission facilities* between two *power operation managers*.

Power shortage occurs during the hour of operation when a *subsystem* is no longer capable of maintaining the demand for a *manual active reserve* which can be activated within 15 minutes.

A **price area** is an *Elspot area* which, due to *bottlenecks* towards another *Elspot area,* has been given an *Elspot price* of its own.

Production shedding means the automatic or manual disconnection of a production facility.

Ramping means restricting changes in *Elspot trading* on one or more cross-border links individually and together from one hour to the next.

Ramp regulation means regulation of power based upon a specified ramp in order to even out the transition between two power levels, normally on HVDC cables at the changes of the hour.

The **reactive reserve** is the reactive power which is activated either automatically or manually during the momentary operational situation.

Redundancy is more than one independent opportunity for a piece of equipment to carry out a desired function.

Regulating bids are bids for upward or downward regulation at a specified output power at a specified price.

Regulating power is activated *regulating bids*, upward and downward regulations at power plants as well as the upward and downward regulation of consumption which producers or consumers offer in exchange for compensation. The *system operators* activate these bids during the momentary operational situation to maintain the balance/frequency within the *balance areas* and to deal with *bottlenecks* on the *transmission network*.

Regulation areas 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 list** is the list of *regulation bids* in ascending and descending order sorted by the price for one hour.

The **regulation margin**, also called **TRM** (Transmission Reliability Margin), is the gap between the *transmission capacity* and the *trading capacity*. It constitutes the scope for the momentary regulation variations as a result of frequency regulation around the planned hourly value for transmission.

The **regulation market** is the market for *regulating power*.

The **regulation price** is the price resulting from implemented regulations during the hour of operation for a *regulation area*. Also called the RK price.

Regulation steps are steps in the *regulation list*.

Restoration is a transition between different operational states characterized by the network being restored, production being regulated upwards, and frequency, voltage and transmission being brought within acceptable limits. Consumption is connected at a pace which the network and production resources can take. Also see *operational states.*

A **risk of power shortage** occurs when forecasts show that a *subsystem* is no longer capable of maintaining the demand for a *manual active reserve* which can be activated within 15 minutes, for the planning period.

Scaling means restricting changes in the *trading capacity* (NTC) between two *Elspot areas* from one hour to the next.

Serious operational disturbances are *operational disturbances* entailing greater consequences than activation of the *frequency controlled disturbance reserve*.

Settlement points are reference points for financial settlement between the *subsystems* based on direct measurement.

The **slow active disturbance reserve** is the active power available after 15 minutes.

Special regulation is the activation of *regulating power* in order to deal with *bottlenecks* on the *transmission network*.

A **subsystem** is the power system for which a *system operator* is responsible. A *system operator* can be responsible for several *subsystems*.

Subsystem balance is calculated as the sum of the measured physical transmissions on the *cross-border links* between the *subsystems*. Thus, there is a deficit if this sum shows that power is flowing into a *subsystem* and a surplus if power is flowing out of a *subsystem*. (Exchanges on *cross-border links* like Finland-Russia, the SwePol Link, the Baltic Cable, Kontek and Western Denmark-Germany are not to be included in the calculation.)

Supportive power is power that adjacent *system operators* can exchange reciprocally as an element of the regulation of balance in the respective *subsystems*. Exchanges are made specifying the power, price, link and time to the exact minute of the start and finish of the exchange. *Supportive power* is settled as the hourly average value.

A **surplus area** is a *subsystem* whose *balance* is positive, i.e. that power is physically flowing out of the *subsystem* measured physically on the *cross-border links* between the *subsystems*.

The **synchronous system** is the synchronously interconnected power system consisting of the *subsystems* of Norway, Sweden, Finland and Eastern Denmark. Western Denmark is synchronously interconnected with the *UCTE* system.

The **system operator** has the *system responsibility* for a defined *subsystem*.

The **system price** is an estimated price for the entire Elspot market. The s*ystem price* is estimated as if there are no capacity limitations on the *transmission network* between the *Elspot areas*.

System protection is composed of automatic system protection equipment for the power system. *System protection* can, for instance, be used to limit the impact of faults by shedding production in order to compensate for the defective component and so that overloads do not arise. *System protection* can also be used to increase the capacity of the *transmission network* without simultaneously increasing the risk of diminishing the *system security*. *System protection* requires a level of reliability in line with primary protection. Previously called network protection.

The **system responsibility** is the responsibility for co-ordinating the utilization of electrical facilities in the jointly operated power system, or a part of this, in order that the desired *system security* and network quality may be attained during operational service.

System security is the power system's ability to withstand incidents such as the loss of lines, bus bars, transformers, production units or consumption.

System services is a generic term for services that *system operators* need for the technical operation of the power system. The availability of *system services* is agreed upon by the *system operator* and the other companies within the respective country. *System services* can be arranged into different forms of *system protection* and *operational reserves* for active and reactive power.

Time deviation is the difference between a synchronous clock driven by the frequency of a power system and planetary time.

The **trading capacity**, also called **NTC** (Net Transfer Capacity), is capacity made available to *Elspot trading* between the *Elspot areas* and the highest permitted sum of the *players'* planned trading on an hourly basis. The *trading capacity* is calculated as the *transmission capacity* less the *regulating margin*.

The **trading plan** is the sum of the *players'* electricity trading between the *Elspot areas* (Elspot, Elbas, hourly trading).

The **transmission capacity**, also called **TTC** (Total Transfer Capacity), is the maximum transmission of active power in accordance with the system security criteria which is permitted in *transmission cross-sections* between the *subsystems/areas* or individual installations.

A **transmission cross-section** is a cross-section on the *transmission network* between the *subsystems* or between *areas* within a *subsystem*. Also referred to solely as cross-sections.

Transmission facilities are individual installations (lines, bus bars, transformers, cables, breakers, isolators etc) which form the *transmission network*. This includes protective, monitoring and control equipment.

A **transmission network** is the interconnected network containing the *transmission facilities*.

UCTE (Union for the Co-ordination of Transmission of Electricity) is an association of *system operators* in continental Europe.

The **voltage controlled disturbance reserve** is the momentarily available active power used for *operational disturbances* and which is activated automatically by the network voltage. Often established as *system protection*.

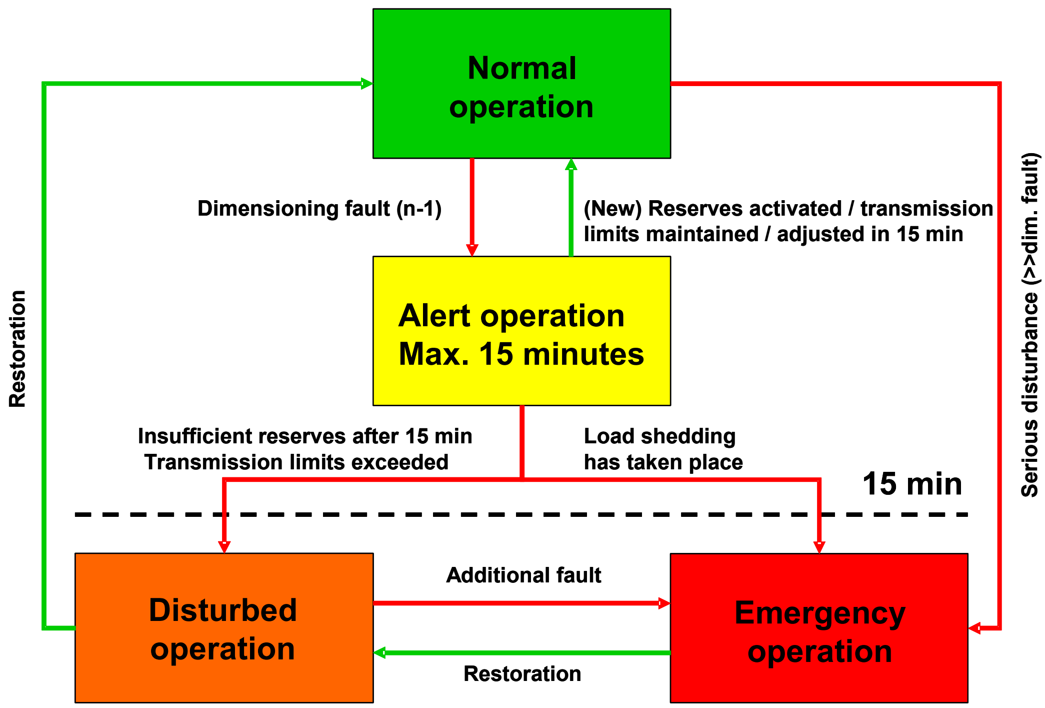

Figure 1 *Operational states (network collapse is not specified in the figure).*

OPERATIONAL SECURITY STANDARDS

1 System security criteria

The following criteria for *system security* are to be applied in those respects that are of significance as regards enabling operation of the power system to be upheld with the *subsystems* interconnected with each other.

The criteria for *system security* shall be based on the *n-1 criterion*. This is an expression of a level of *system security* entailing that a power system is assumed to be intact apart from the loss of individual principal components (production units, lines, transformers, bus bars, consumption etc.). For faults having the largest impact on the power system, the term *dimensioning faults* is used.

It is not normally the same type of fault that is dimensioning during frequency disturbances as during disturbances to the transmission system. The loss of the power system's largest production unit is normally dimensioning as regards determining the *frequency controlled disturbance reserve*.

The definition of *serious operational disturbances* is *operational disturbances* having a greater impact than activation of the *frequency controlled disturbance reserve*.

The definition of *normal state* is an operational state entailing that all consumption is being met, that the frequency, voltage and transmission lie within normal limits and that the reserve requirements have been met. The power system has been prepared in order to deal with *dimensioning faults*.

For the interconnected Nordic power system, the above entails that:

- a dimensioning fault on a subsystem must not bring about serious operational disturbances in other subsystems. This places demands on the frequency controlled disturbance reserve and the transmission capacity within and between the subsystems
- if the power system is not in normal state following an operational disturbance, the power system must have been restored, within 15 minutes, to normal state. This places demands on the available fast active disturbance reserve. If there are exceptions from the time requirement, or if there is a departure from the above definition of dimensioning faults, then there must be consultation between the system operators concerned.

2 System protection

System protection is used to limit the consequences of faults over and above the disconnection of defective components. *System protection* can have as its purpose to increase the *system security*, the *transmission capacity,* or a combination of these. For *system protection* that is used to increase the *transmission capacity,* the following requirements have been set:

- An analysis must be implemented which shows the consequences for the power system in the event of a correct, unwanted and missing function hereby taking the interaction with other system protection schemes into account.

- In the event of a correct or unwanted function, *serious operational disturbances* will not be accepted in other *subsystems.*
- If the above consequence analysis shows that a missing function can entail *serious operational disturbances* for other *subsystems,* the following technical requirements shall apply to the *system protection* function:

  - **Redundant telecommunications shall exist in cases where system protection is dependent on telecommunications**

    Redundant telecommunications means that communications between the stations concerned shall be entirely duplicated. If the auxiliary power feed for one of the communications systems fails, then the other must not be affected. In practice, this means that batteries, telecom terminals, converters and communication paths must be duplicated. Communication paths may not, on any section, share connections, leads, opto cables or similar. They must take geographically separated routes.

    Multiplexed links can be used but communications shall use separated multiplexes that are not fed by the same battery. Having separate fuses on the same battery does not constitute full redundancy.

  - **There must be real time monitoring of telecommunications**

  - **There must be a redundant and independent ”triggering function”**

    A *redundant* triggering function, if this relates to breakers, means that the breaker has two trip magnets. Breaker fault protection shall be used to safeguard breaker operation if the ordinary breakers are not functioning correctly

  - **The control facility and telecommunications standard shall be on the same acceptable reliability level as the one applicable to primary relay protection**

- If a consequence analysis shows that a missing function will not entail *serious operational disturbances* for other *subsystems*, the relevant *subsystem's system operator* will decide which requirements apply to the *system protection* function.
- If a consequence analysis shows that a correct, unwanted or missing function can lead to more extensive consequences than dimensioning faults, system protection must be accepted separately between the parties.

3 HVDC links

HVDC links shall be regarded as production facilities.
The *system operators* for the individual HVDC links are only responsible for restoring the operation to *normal state* in their own *subsystems* after the loss of the HVDC link or after *emergency power* regulation has been activated.

4 Operational reserves

4.1 Automatic active reserve

The *automatic active reserve* is divided up into the *frequency controlled normal operation reserve*, the *frequency controlled disturbance reserve* and the *voltage controlled disturbance reserve*.

4.1.1 Frequency controlled normal operation reserve

The *frequency controlled normal operation reserve* shall be at least 600 MW at 50.0 Hz for the synchronous system. It shall be completely activated at f = 49.9/50.1 Hz (Δf = +- 0.1 Hz).
In the event of a rapid change of frequency to 49.9/50.1 Hz, the reserve shall be regulated upwards/downwards within 2-3 minutes. The *frequency controlled normal operation reserve* is distributed between the *subsystems* of the *synchronous system* in accordance with the *annual consumption* (total consumption exclusive of power plant's own consumption) during the previous year.

The factual distribution of the *frequency-controlled normal operation reserve* between the *subsystems* shall be revised each year before 1 March on the basis of *annual consumption* in the previous year and rounded to the closest ten. *Annual consumption* shall be given in TWh with an accuracy of one decimal.

Each *subsystem* shall have at least 2/3 of the *frequency-controlled normal operation reserve* in its own system in the event of splitting up and island operation.

For 2006, the following distribution applies:

	Annual consumption 2005 (TWh)	Frequency controlled normal operation reserve (MW)
Eastern Denmark	*14.4*	*23*
Finland	*84.9*	*137*
Norway	*125.9*	*203*
Sweden	*147.3*	*237*
Synchronous system	*372.5*	*600*

4.1.2 Frequency controlled disturbance reserve

There shall be a *frequency controlled disturbance reserve* of such magnitude and composition that *dimensioning faults* will not entail a frequency of less than 49.5 Hz in the *synchronous system*.

Taking into account the frequency-dependence of consumption, the above requirements entail that the combined *frequency controlled disturbance reserve* shall amount to an output power equal to the *dimensioning faults* less 200 MW. The overall *frequency controlled disturbance reserve* must be able to be used until the *fast active disturbance reserve* has been activated.

Upward regulation of the *frequency controlled disturbance reserve* must not give rise to other problems in the power system. When setting the *transmission capacity*, localization of the *frequency controlled disturbance reserve* must be taken into account. Each *subsystem* shall have at least 2/3 of the *frequency controlled disturbance reserve* within its own system in the event of splitting up and island operation.

The *frequency controlled disturbance reserve* shall be activated at 49.9 Hz and be completely activated at 49.5 Hz. It must increase as good as linearly throughout the frequency range of 49.9-49.5 Hz.

The major part of both the *frequency controlled disturbance reserve* and the *frequency controlled normal operation reserve* will be achieved via automatic frequency regulation for production facilities. To meet the above requirements, the objective for each respective *system operator* must be to place demands on turbine regulator settings, e.g. in the form of demands regarding regulating time constants. There should also be the possibility of monitoring and checking.

Agreed automatic *load shedding,* e.g. industrial, district heating and electric boiler consumption in the event of frequency drops to 49.5 Hz can be counted as part of the *frequency controlled disturbance reserve*. The following requirements are applicable, however:

> *Load shedding* can be used as *frequency controlled disturbance reserve* in the frequency range of 49.9 Hz to 49.5 Hz, when *load shedding* meets the same technical requirements set below for generators.

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.

Distribution of the requirement for the *frequency controlled disturbance reserve* between the *subsystems* of the *interconnected Nordic power system* shall be carried out in proportion to the *dimensioning fault* within the respective *subsystem*. Distribution of the requirement shall be updated once a week or more often if necessary.

The following example shows how distribution of the requirement for the *frequency controlled disturbance reserve* is achieved:

	Dimensioning faults (MW)	Frequency controlled disturbance res. (MW)	Frequency controlled disturbance res. (%)
Denmark	580	153	15.0
Finland	865	228	22.4
Norway	1,200	317	31.0
Sweden	1,220	322	31.6
Total		1,020	100

Energinet.dk's requirement of the *frequency controlled disturbance reserve* is distributed between Eastern and Western Denmark as follows:

- Western Denmark 75 MW (7.4%)

- Eastern Denmark 78 MW (7.6%)

Energinet.dk accepts this requirement as long as E.ON Netz and UCTE accept the emergency power setting on the HVDC Skagerrak and Konti-Skan links and as long as this entails no financial consequences for Energinet.dk. Energinet.dk will not reserve trading capacity in order to be able to deliver the reserve.

Energinet.dk's AC joint operation of Western Denmark within the *UCTE* system entails that Energinet.dk is required to maintain the frequency and *frequency controlled disturbance reserve* in accordance with *UCTE* rules. This is described in section 5 ”Special conditions for Energinet.dk as a member of UCTE”.

4.2 Fast active disturbance reserve

The *fast active disturbance reserve* shall exist in order to restore the *frequency controlled normal operation reserve* and the *frequency controlled disturbance reserve* when these reserves have been used or lost, and in order to restore transmissions within applicable limits following disturbances.

The *fast active disturbance reserve* shall be available within 15 minutes.

The *fast active disturbance reserve* shall exist and be localized to the extent that the system can be restored to *normal state* following faults.

The size of the *fast active disturbance reserve* 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 *system operators* have secured, through agreement or ownership, a *fast active disturbance reserve*. This reserve consists of gas turbines, thermal power, hydropower and *load shedding*. In round figures, Fingrid has 1,000 MW, Svenska Kraftnät 1,200 MW, Energinet.dk 600 MW in Eastern Denmark (where 300 MW is *slow active disturbance reserve* which, on special occasions, can be made fast), Energinet.dk 620 MW in Western Denmark, and Statnett 1,600 MW.

Whenever required, a *subsystem* can hold a certain amount of *fast active disturbance reserve* for another *subsystem*, if there is idle *transmission capacity* for this purpose. The keeping of such reserves is to be agreed upon between the concerned *subsystems' system operators* upon each occasion, and all *system operators* shall be informed of this.

4.3 Slow active disturbance reserve

The *slow active disturbance reserve* is active power available after 15 minutes.

4.4 Reactive reserve

Within each *subsystem,* there must be a reserve of reactive power which is constituted in such a way with regard to size, regulation capability and localization that *dimensioning faults* will not entail a system collapse.

5 Special conditions for Energinet.dk as a member of UCTE

N-1 security
The *n-1 criterion* also applies to the *UCTE* area. If n-1 security is maintained with the help of adjacent systems (e.g. using *system protection*), this shall be approved by the adjacent system owners.

Primary regulation
For the entire *UCTE,* a *frequency response* of 18,000 MW/Hz is required. The dimensioning production loss is 3,000 MW. The different countries' share of the primary regulation reserve is distributed in proportion to the individual countries' production capacities. Energinet.dk shall thus, during 2006, be able to deliver 32 MW as *frequency controlled disturbance reserve* in Western Denmark. This *frequency controlled disturbance reserve* shall be fully activated in the event of a momentary frequency change of ± 200 mHz.

Secondary reserve
Generally within *UCTE,* it is applicable that the delivery of secondary reserve shall be commenced 30 seconds after an imbalance has arisen between production and consumption and shall be fully regulated out after 15 minutes. There must be sufficient reserve to safeguard each area's own balance following a loss of production.

6 Principles for determining the transmission capacity

6.1 Introduction

The various *system operators'* ability to transmit power shall be calculated for each state of operation. This applies both to transmissions within each *subsystem* and to exchanges between *subsystems*. Most frequently, this is achieved by means of a *transmission cross-section* being defined, and static and dynamic simulations determine how much power can be transmitted in any direction through the cross-section before thermal overloads, voltage collapse and/or instability arise following a *dimensioning fault* (for the cross-section) being added. In the cross-section, an arbitrary number of lines on different levels of voltage can be included.

The result of the calculations will be the maximum technical limitation for transmission. For the operational phase, this limit must be reduced as regards the calculatory inaccuracy and normal variations due to frequency controlled normal operation regulation.

6.2 Thermal limitation

In cases when thermal limitations on lines and/or equipment restrict the *transmission capacity* through a *transmission cross-section*, the maximum transmission capability through a cross-section, or for single lines following a simple fault, can be set at a given percentage over the nominal limit in cases when the cross-section/line can be relieved within 15 minutes.

6.3 Voltage collapse

It is neither of interest nor possible to specify exactly at which voltage a voltage collapse occurs as this will vary with the state of operation and access to active and reactive synchronized production at the onset of the fault. Some events that low voltage can lead to are:

- Consumers being affected at a voltage of 0.5-0.7 p.u. (contactors open)

- Risk of overloading equipment at 0.8 p.u.
- Risk of production being shed due to low voltage on auxiliary power equipment (0.85 p.u.)
- Reactive resources being exhausted, i.e. generators are at their current limits for rotors and stators. Can appear at a voltage of 0.85-0.9 p.u.

Neither is it possible to specify a global value for the calculatory inaccuracy. This is different for each *system operator* and *transmission cross-section* and primarily depends on the quality of data, representation of the underlying systems and the calculation technique used. The margin for primary voltage regulation is set by each *system operator* for internal cross-sections and bilaterally between the *system operators* for cross-sections between systems.

6.4 System dynamics

Dynamic simulation of a power system before, during and after a fault provides, as a typical result, how the different production facilities' generators oscillate against each other. These oscillations can either be attenuated after a while or accelerated. Today there is no accepted norm for how quickly the oscillations must be attenuated in order for the system to be assumed to be stable; rather this is a matter of judgement. In the same way as above, the calculated technical limit is reduced using a calculatory inaccuracy margin.

A fault scenario is to be simulated over a period so lengthy that all conceivable oscillation frequencies can be detected and that these are well attenuated.

BALANCE REGULATION STANDARDS

The work of *balance regulation* shall be conducted in such a way that regulations take place in the *subsystem* with the lowest regulation cost. *Parties* carrying out regulation shall be compensated for their costs.

1 Balance regulation within the synchronous system

Balance regulation within the *synchronous system* shall be conducted in such a way that the below specified quality standards regarding frequency and *time deviation* are integrated. Requirements regarding *frequency response* and frequency controlled reserves (see appendix 2) shall be maintained. Furthermore, *balance regulation* shall be conducted in such a way that the *transmission capacity* is not exceeded.

Sweden and Norway represent approx. 75% of the *annual consumption* of the *synchronous system*. The *Parties* agree that Svenska Kraftnät and Statnett will thus have the task of maintaining the frequency and *time deviation* within the set limits. Fingrid and Energinet.dk will normally only *balance-regulate* after contacting Svenska Kraftnät. Energinet.dk West will exchange *supportive power* with the *synchronous system* after contacting Statnett.

The distribution of work between Svenska Kraftnät and Statnett is regulated bilaterally and communicated to all the *Parties*.

1.1 Quality standards

Frequency
The requirement of the highest permissible variation in the frequency during *normal state* is between 49.90 and 50.10 Hz. The goal is to maintain 50.00 Hz.

In certain operational situations it may be necessary to deviate from the normal activation sequence and go over to *regulating bids* on the regulating list in order to maintain the frequency.

Time deviation
The *time deviation* is used as a tool for ensuring that the average value of the frequency is 50.00 Hz.

The *time deviation* ΔT shall be held within the time range of - 30 to + 30 seconds. At $\Delta T = 15$ seconds, Statnett and Svenska Kraftnät shall contact each other in order to plan further action.

The frequency target has a higher priority than the *time deviation* and the costs of frequency regulation.

The *time deviation* shall be corrected during quiet periods with high *frequency response* and with a moderate frequency deviation.

Joint operational planning
There shall active communications between Statnett and Svenska Kraftnät before each hour of operation and *day of operation* in order to jointly draw up a suitable strategy and to plan future

action so that the above goals are achieved. Both parties are responsible for maintaining sufficiently active communications.

Information on planned and taken action in order to achieve the above goals shall be delivered to Fingrid and Energinet.dk.

1.2 Momentary area control error

Momentary area control errors are calculated for each *subsystem* and used as an instrument for measuring the *subsystem's* momentary imbalance. Momentary area control errors are not normally used as regulation criteria.

Area control errors (I) are calculated in accordance with the following formula:

$I = P_{mom} - P_{plan} + \Delta f \times R$

P_{mom} = the momentary reading on the links between the *subsystems*

P_{plan} = the exchange plan including *supportive power* between the *subsystems*

Δf = frequency deviation

R = momentary *frequency response*

2 Balance regulation in Western Denmark

Balance regulation in Western Denmark shall take place so that the requirements concerning Western Denmark as a "control block" in UCTE are met on the *cross-border links* between Germany and Jutland.

3 Regulation measures and principles of pricing

A joint list of *regulation bids* is compiled, in the order of price, containing 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 *subsystems* in the *synchronous system* primarily takes place in the form of *balance power*. *Balance power* can be exchanged as long as this does not cause unacceptable conditions for the adjacent areas. Power exchange between the *synchronous system* and Western Denmark primarily takes place in the form of *supportive power*.

3.1 Regulation of frequency and balance

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.

For each hour, the *regulation price* is determined in all *Elspot areas*. The *regulation price* is set at the margin price of activated bids in the joint *regulation list*. When *bottlenecks* do not arise during the hour of operation, the prices will be equal. The available capacity during the hour of operation can be utilised even there is a bottleneck in Elspot so that a joint *regulation price* is obtained. If there has been no regulation, the *regulation price* is set as the *area price* in Elspot.

When a *bottleneck* arises during the hour of operation between *Elspot areas* which entails that a bid in an area cannot be activated, the relevant area will obtain a *regulation price* of its own. This *regulation price* will be decided by the last bid activated in the joint *regulation list* prior to the *bottleneck* arising.

There is a *bottleneck* between the *Elspot areas* when it is not "possible" to carry out *balance regulation* on the basis of a joint *regulation list* without deviating from the normal price order of the list. The reason for this not being "possible" can be for example levels of transmission that are too high on the *cross-border link* itself or on other lines/*transmission cross-sections* or operational/trading rules which entail that it is not permitted to activate bids in the joint *regulation list*.

If the transmission between *Elspot areas* is greater than the *trading plan* and this creates *bottleneck problems* for other *Elspot areas*, the area(s) which caused this will regulate against the balance. The area(s) therefore obtain(s) its/their own *regulation price(s)*. This will be decided by *balance regulations* within the area or within several adjacent areas that are affecting the *bottleneck* in the same way.

During bidirectional regulation for an hour in the *synchronous system*, the net regulated energy will decide whether the *regulation price* will be the upward or downward regulation price. If no regulation has taken place or if the net volumes upwards and downwards are equal, the price will be set at the *Elspot price*. Regulation behind a *bottleneck* will only affect the net volume if the *bottleneck* has arisen through activated *balance regulations*. This also applies to Western Denmark.

Bottlenecks to/from an *Elspot area* which are caused by imbalances within an *Elspot area* are dealt with as *balance regulation* and give rise to a divided *regulation market*. *Bottlenecks* caused by a reduced *transmission capacity* to/from an *Elspot area,* after Elspot pricing, are managed using *counter trading* and *special regulations*.

A prerequisite for the *system operator* in the *synchronous system* to be able to set his own *regulation price* is that the *trading plan* is exceeded. In the opposite case, *counter trading* could be necessary between the *system operators*.

3.2 Regulation for network reasons

Regulations carried out for network reasons shall not, in the basic case, affect the r*egulation price* calculation*,* but they are carried out as *special regulations*.

For regulations for network reasons in internal cross-sections in an *Elspot area*, bids are used in the *subsystems* which rectify the network problem. When choosing a regulation object, attention must be paid to both the price and the effectiveness of the regulation.

For regulations carried out for network reasons on the border between *Elspot areas*, the cheapest bids are normally used in the *subsystems* which rectify the network problem. When such regulation is caused by an imbalance vis-à-vis the *trading plan* between *Elspot areas*, the *regulation price* will be affected in the subnetwork where the regulation was carried out.

4 Pricing of balance power

4.1 Balance power between the subsystems within the synchronous system

Balance power between two *subsystems* is priced at the average of the *regulation prices* in these *subsystems*.

4.2 Balance power between Western Denmark and Sweden

Swedish *regulation prices* apply to the pricing of *balance power* between Western Denmark and Sweden in accordance with the dual price model applied internally within Sweden.

4.3 Balance power between Western Denmark and Norway

Norwegian *regulation prices* apply to the pricing of *balance power* between Western Denmark and Norway.

5 Pricing of supportive power

5.1 Pricing within the synchronous system

When there is a need to *exchange supportive power* between two *Parties*, the price will be set at the regulating *Party's* cost, and conclusively set after the hour of operation. The price of *supportive power* shall not normally affect the *pricing of balance power* between the *subsystems*.

5.2 Pricing between Western Denmark and Norway, and Western Denmark and Sweden

The following applies to *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.

5.3 Pricing during operational disturbances on cross-border links

The price of *supportive power* during *counter trading* which is due to an *operational disturbance* on the *cross-border link* itself will be the average of the *area prices* in Elspot in the adjacent systems.

6 Operational/trading rules between the synchronous system and Western Denmark

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 West 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 West.

Statnett and Energinet.dk West 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.

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 plan shall normally be carried out in a maximum of 15 minutes.

EXCHANGING INFORMATION

The purpose of this Appendix is to describe the information which shall routinely be exchanged between the concerned *Parties* to an extent which is significant for the collaboration between the *Parties* in respect of system operation and balance management.

The technical description (network model, network data etc.) of the power system is governed by other agreements.

Information to be provided to the *players* on the electricity market is governed by the *system operators'* agreement vis-à-vis Nord Pool Spot.

1 Outage planning

Plans for outages having impact on the *transmission capacity* between the *subsystems* or which are in some other way significant for *system security* or the electricity market shall be exchanged and co-ordinated between the *Parties* concerned. Plans shall be advised for up to one year forward in time. Alterations to plans shall be advised as soon as possible.

The impact of such outages on the *transmission capacities* between the *subsystems* shall also be exchanged. Preliminary values shall be exchanged as early on as possible. Final values shall be exchanged immediately following approval of the capacities.

Outages having impact on the *transmission capacity* between the *subsystems* shall be entered in the joint Nordic outage planning system NOPS (Nordic Outage Planning System).

2 Prior to the hour of operation

Information which is to be routinely exchanged between the *Parties* prior to the hour of operation:

- Plans for the *transmission capacities* and *trading capacities* on the links between the *subsystems* on an hourly basis
- Current limitations within the *subsystems*
- Forecast of available *frequency controlled normal operation reserve*, *frequency controlled disturbance reserve* and *fast active disturbance reserve*
- Forecast of *dimensioning faults*
- Changes to the network configuration of significance to the *subsystems' system security* and the impact of these changes
- Changes to settings of regulation equipment and automatic systems
- Hourly *exchange plans* and *trading plans* between the *subsystems*
- Hourly *exchange plans* for non-Nordic links
- Hourly plans or forecasts regarding the overall production and consumption. Quarter-hourly plans for production shall be exchanged to the extent these are available.

- Plans for *counter trading* between the *subsystems*
- *Regulation bids*.

The joint Nordic information system NOIS (Nordic Operational Information System) shall be used for the exchange of information which is necessary in *balance regulation* (regulation bids, production plans and HVDC plans, consumption forecasts etc.).

3 During the hour of operation

Information which must routinely be available to the *Parties* during the hour of operation:

- Ongoing outages
- Authorization-dependent *transmission capacity* and parameters of significance in this regard (e.g. *system protection*)
- *Counter trading*/*special regulation* and other corresponding measures concerning the other *Parties*
- An account of events and disturbances of a major character, together with implemented measures
- Volume and duration of requested *load shedding* in the event of *power shortages*.

Measured values and status indications to be exchanged between the *Parties* during the hour of operation:

- Transmission of reactive and active power on the individual links, plus the sum of the active power between the *subsystems*
- Transmission of reactive and active power on the individual links, plus the sum of the active power to systems outside the Nordic power system provided that the counterparty approves of this
- Active power in critical *transmission cross-sections* within the *subsystems*
- Activated regulations and current prices for regulating imbalances upwards and downwards
- Area control errors
- Surpluses/deficits as defined in Appendix 9
- Overall production and consumption
- Production at power plants that are critical to the *interconnected Nordic power system's* operational situation
- *Frequency response* and available *frequency controlled normal operation reserve*, *frequency controlled disturbance reserve* and *fast active disturbance reserve*. If measured values are not available, forecasts shall be exchanged.
- Measurements that are needed for monitoring the stability of the power system.

4 Following the hour of operation

Information which must routinely be exchanged between the *Parties* following the hour of operation:

- Activated upward and/or downward regulation volume and *regulation prices*
- Reconciliation of previous calendar day's exchanges, *frequency response*, deals, prices etc, in accordance with the settlement routines
- Measured values on the links between the *subsystems* in accordance with other relevant agreements
- An account of events and disturbances, together with implemented and planned measures, to be rendered as soon as possible.

SYSTEM PROTECTION

1 General

Automatic *system protection* is used to limit the impact of faults by means of measures over and above disconnecting the defective component. *System protection* can be used to increase the *system security*, the *transmission capacity,* or a combination of these. For *system protection* which is used to increase the *transmission capacity,* requirements have been set. These are specified in Appendix 2 of the System Operation Agreement.

Automatic *system protection* uses two different principles of operation. One of these is *system protection* that is activated via measurements of the system state, e.g. the voltage at a critical point or the system frequency. The other is *system protection* that is activated by predetermined events, e.g. one or more relay signals from the facilities' protective equipment.

Automatic *system protection* limits the consequences of operational disturbances in one or more of the following ways:

- regulation of DC facilities, *emergency power*
- production shedding or downward regulation of production
- load shedding and, in some cases, reactive shunts
- start-up of production
- network switchings.

Automatic *system protection* is adapted to the combined *operational reserves* of the *interconnected Nordic power system*. Frequency controlled functions are shown in Figure 1. A detailed description of the Figure can be found in the Nordel report ”Rekommandasjon for frekvens, tidsavvik, regulerstyrke og reserve” from August 1996. Minor frequency deviations are dealt with by the *frequency controlled disturbance reserve* on generators. Major frequency deviations start up regulation at the DC facilities. At lower frequencies, automatic *load shedding* starts up.

Frequency controlled actions in the NORDEL-system

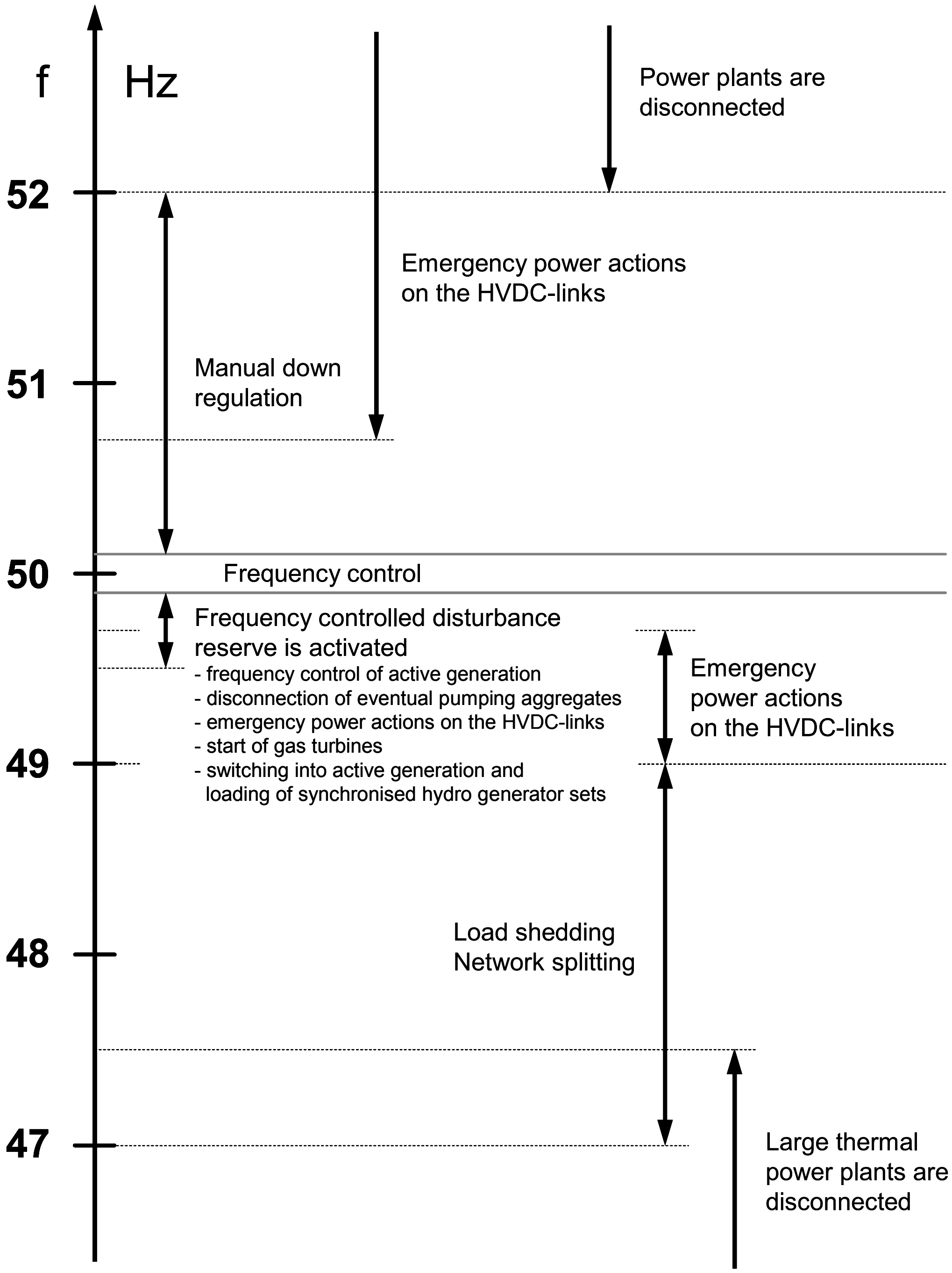

Figure 1 Frequency controlled actions in the Nordel-system

2 System protection activated by frequency deviations

Frequency controlled *system protection* activated by a deviating frequency:

- regulation of DC facilities, *emergency power*
- *production shedding* or downward regulation of production, PFK
- start-up of production
- *load shedding*, AFK
- network switchings.

A low frequency during *operational disturbances* is traditionally dealt with using *frequency controlled disturbance reserve*.

Frequency controlled disturbance reserve is dimensioned to maintain the frequency within permissible limits in the event of *operational disturbances*. If this is not successful and the frequency continues to drop, *load shedding*, for instance, might curb the frequency drop. The increased use of frequency controlled regulation of DC installations, *emergency power*, is in order to prevent major frequency drops.

A high frequency is traditionally dealt with using the downward regulation of production or, in extreme situations, using *load shedding.* In this case too, there will be an increased use of the frequency controlled regulation of DC installations.

2.1 Frequency controlled regulation of DC installations, Emergency power

The maximum impact of regulation of DC installations during frequency drops can be seen in Figure 2. As illustrated by the Figure, all DC installations between *the synchronous system* and other AC systems contribute frequency controlled *emergency power*. It should be pointed out, however, that if a DC installation is performing a full import to an area with a low frequency, it will not be able to contribute *emergency power*.

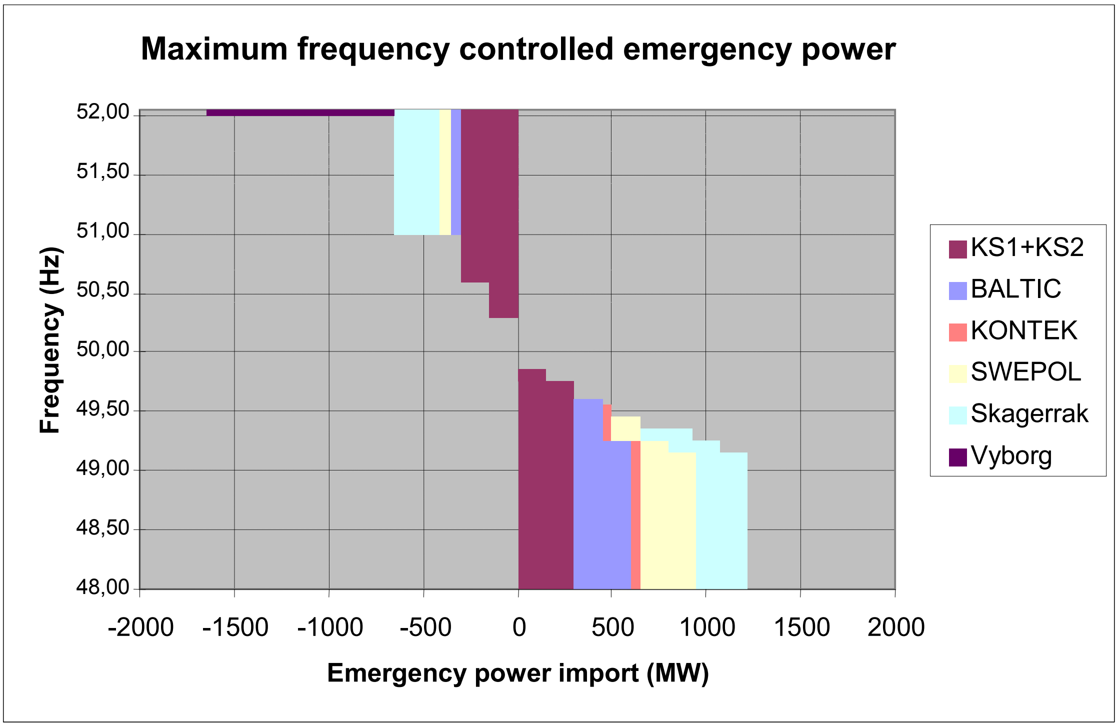

Figure 2 Maximum frequency controlled emergency power

The Vyborg DC link is disconnected at a frequency in Finland of > 52 Hz for 0.5 sec.

2.2 Frequency controlled start-up of production

Automatic frequency controlled start-up of production is carried out in order to increase the number of production units in the power system during *operational disturbances*.

Hz	Denmark East	Denmark West	Norway	Sweden	Finland
49.8		25 MW GT			
49.7-49.5				520 MW GT in three stages of 0.1 Hz	180 MW GT, 15 sec
49.5					

Schedule 1

2.3 Frequency controlled load shedding

If a frequency drop cannot be curbed by the regulation of DC installations and the frequency continues to drop, automatic *load shedding* will occur. This will take place in accordance with Schedule 2:

Denmark	East	10 % of consump. f<48.5 Hz momentary, f<48.7 Hz 20 sec. 10 % of consump. f<48.3 Hz momentary, f<48.5 Hz 20 sec. 10 % of consump. f<48.1 Hz momentary, f<48.3 Hz 20 sec. 10 % of consump. f<47.9 Hz momentary, f<48.1 Hz 20 sec. 10 % of consump. f<47.7 Hz momentary, f<47.9 Hz 20 sec.
	West	15 % of consump. f<48.7 25 % of consump. f<47.7
Norway		7,000 MW* in stages from 49.0 Hz to 47.0 Hz
Sweden	South of cross-section 2	electrical boilers and heat pumps P ≥ 35 MW. f< 49.4 for 0.15 sec 35>P ≥ 25 MW. f< 49.3 for 0.15 sec 25>P ≥ 15 MW. f< 49.2 for 0.15 sec 15>P ≥ 5 MW. f< 49.1 for 0.15 sec 30 % of consump in 5 stages stage 1. f< 48.8 for 0.15 sec stage 2. f< 48.6 for 0.15 sec stage 3. f< 48.4 for 0.15 sec stage 4. f< 48.2 for 0.15 sec. f<48.6 for 15 sec stage 5. f< 48.0 for 0.15 sec. f>48.4 for 20 sec
Finland		10 % of consump. f<48.5 Hz 0.15 sec. f<48.7 Hz 20 sec 10 % of consump. f<48.3 Hz 0.15 sec. f<48.5 Hz 20 sec

Schedule 2

* For Norway, this refers to peak loads.

2.4 Frequency controlled disconnection of lines

Denmark	East	Disconnection of the Swedish link at f<47.0 Hz for 0.5 sec or f<47.5 for 9 sec
	West	-
Norway		-
Sweden		-
Finland		Disconnection of Vyborg DC link at a frequency in Finland of >52 Hz for 0.5 sec Disconnection of northern AC links to Sweden at a frequency of > 50.7 for 2 sec if imports from Sweden are > 900 MW and the voltage on the 400 kV network is < 380 kV.

3 System protection activated by voltage deviations

In Sweden, there are two important types of *system protection* which are controlled by voltage. Both types of *system protection* regulate down exports to the continent on HVDC links in the event of a risk of voltage collapse or overloads on important lines.

3.1 System protection in Sweden cross-section 2

The *System protection* that is to relieve cross-section 2 during *operational disturbances* measures the voltage at 4 stations north of cross-section 2; Storfinnforsen, Kilforsen, Stornorrfors, and Hjälta. When the voltage has been lower than 390 kV for 2 seconds, a signal will be sent to the *system protection*. If the voltage has been low in at least two of the stations, the *system protection* will send a signal to Fenno-Skan (*emergency power* 400 MW) and Konti-Skan 2 (*emergency power* 100 MW).

3.2 System protection in Sweden cross-section 4

The *System protection* will regulate down the transmissions on three DC links to the continent when the voltage in southern Sweden falls below 390 kV. In doing so, cross-section 4 will be relieved immediately in the event of an *operational disturbance*. When *system protection* is in operation, a higher level of transmission will be allowed in cross-section 4 (2/3 of the *emergency power* intervention). The increased capacity in cross-section 4 may only be used when consumption south of cross-section 4 is less than 4,500 MW.

System protection obtains measured values from 6 substations: Breared, Hallsberg, Hjälta, Kilanda, Tenhult and Sege. When *system protection* is in operation, a higher level of transmission will be allowed in cross-section 4. The increase will accrue on the respective overseas interconnector, Baltic Cable, the SwePol link and Öresund connection.

The criterion for the activation signal of *system protection* is that the voltage in one of these six points goes under 390 kV for 4 seconds. Upon activation, there will be a power change of 200 MW northbound for Baltic Cable (BC emergency power control entry 3), 250 MW northbound for Kontek, and 300 MW northbound for the SwePol Link (SwePol emergency power control entry 4). For the SwePol Link to become activated, it is also necessary that the voltage at Stärnö is lower than 415 kV.

3.3 System protection in southern Norway

In Norway, there is *system protection*, which is voltage-controlled. The Skagerrak cables have *emergency power* regulation which is controlled by local voltage measurements at Kristiansand. A low voltage of 275 and 270 kV will provide 200+200 MW of relief.

3.4 System protection in Finland

In Finland, there is *system protection* which is controlled by voltage and the transmission between Sweden and Finland at the critical *transmission cross-section* in Finland (north - south). The s*ystem protection* uses *emergency power* regulation with automated systems on the HVDC Fenno-Skan link. The *system protection* provides a power change of 200 or 400 MW to Finland.

The four types of *system protection* are shown in Figure 3.

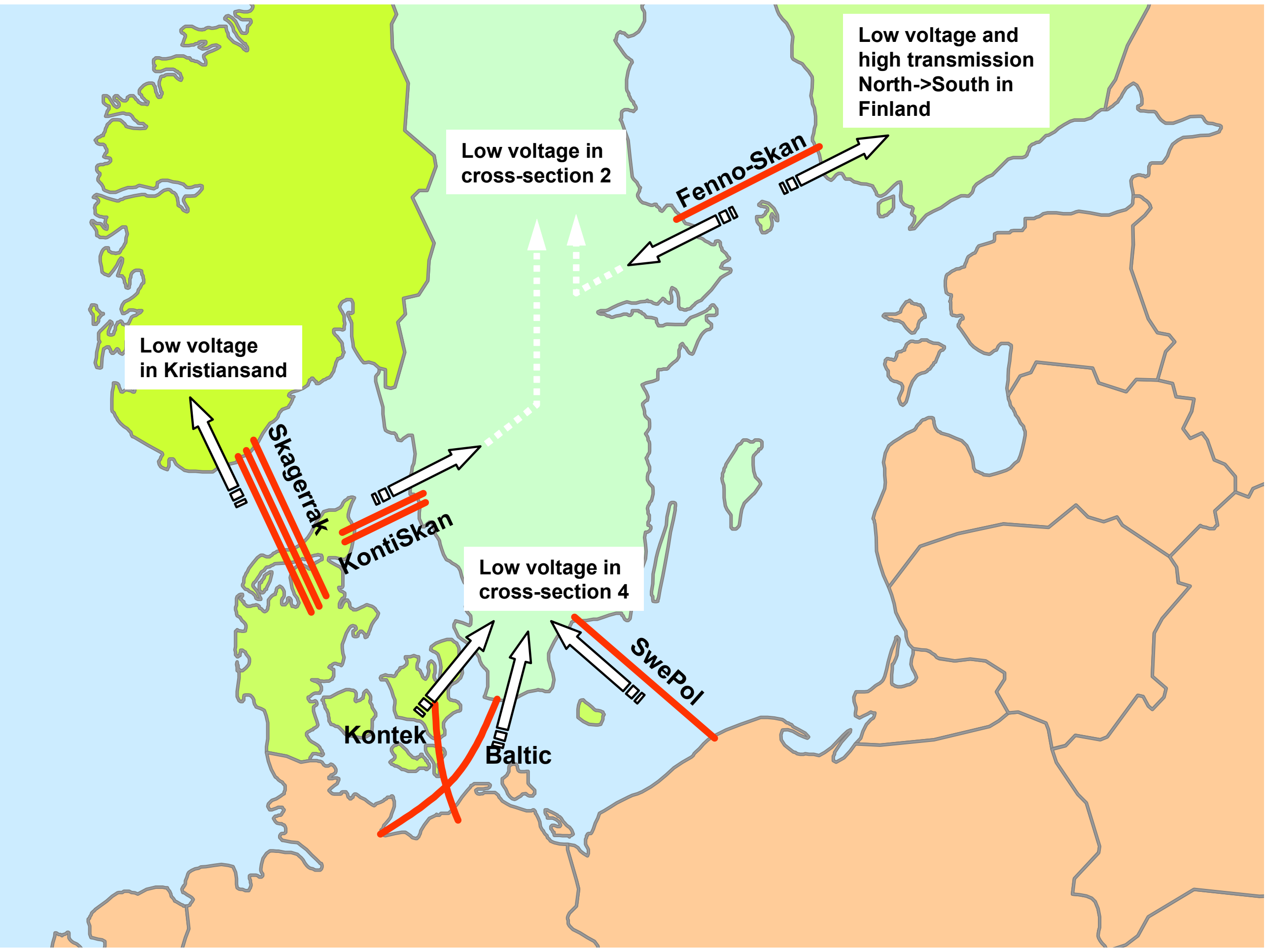

Figure 3 *Control of HVDC-links on low voltage*

4 System protection activated by one or more relay signals from the facilities' protective equipment

System protection activated by relay signals is often more complicated and the protection often controls facilities a long way from the relays. Figure 4 shows an overview of *system protection* for *production shedding* and/or control of the HVDC links. Figure 5 shows an overview of *system protection* for *load shedding* and/or network division.

The Figures are followed by a description of the *system protection*.

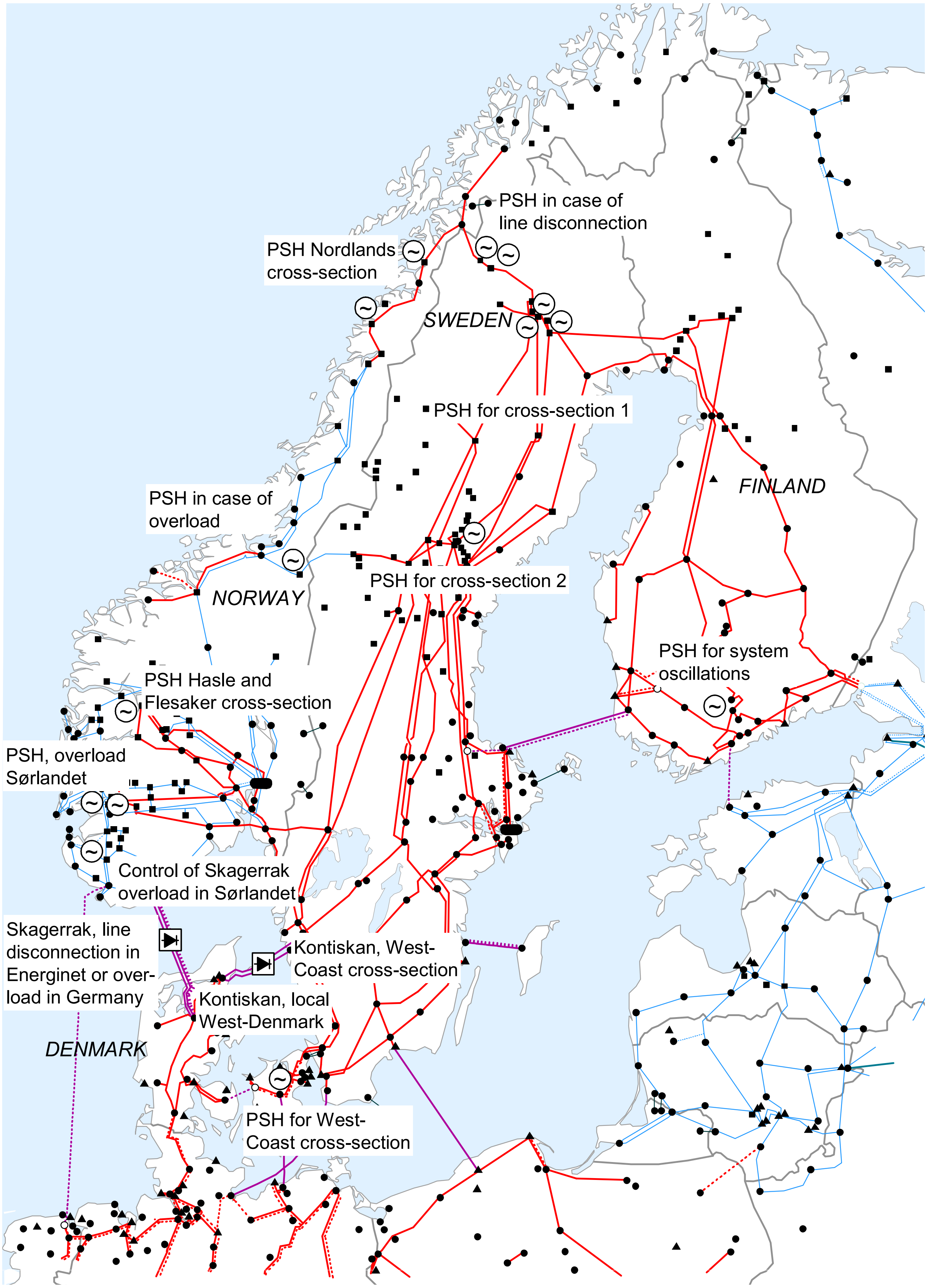

Figure 4 *System Protection based on Production Shedding (PSH) or Control of HVDC-links*

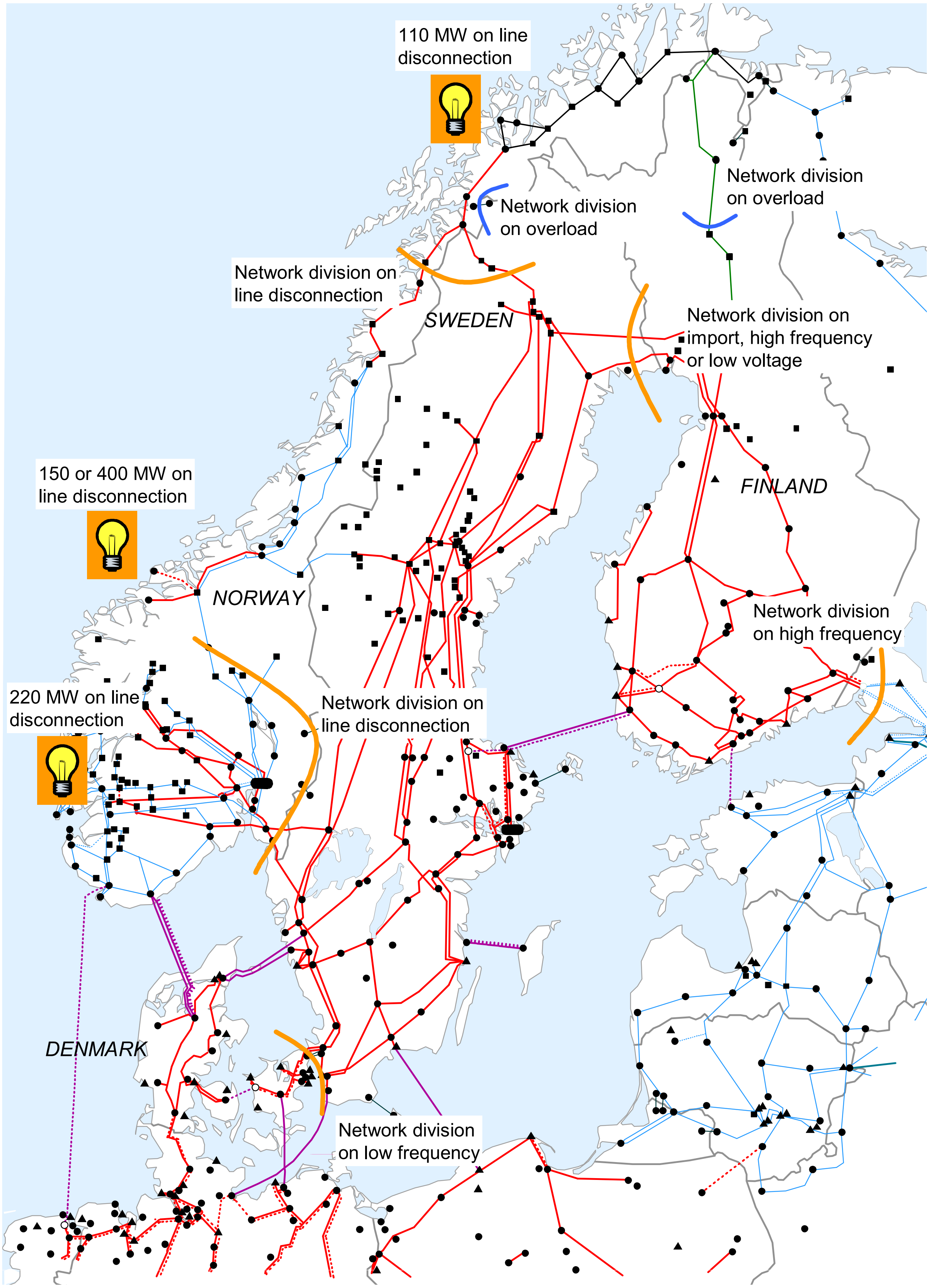

Figure 5 System Protection based on Load Shedding or Network Division

4.1 Eastern Denmark: System protection for stability in Eastern Denmark

Disconnection of gas turbines and downward regulation of the steam turbine at unit 2 of the Avedøre plant upon activation of certain breakers on the 400 kV network in Zealand. This *system protection* is only activated during operational situations when critical 400 kV network components are disconnected or during high export volumes towards Sweden.

4.2 Sweden: System protection with production shedding for limiting overloads on lines in Sweden

Shedding of hydropower production in northern Sweden via remotely-transmitted signals from activated protection functions. Extent of approx. 1,600 MW of installed power. Upon disconnection of lines in cross-section 1, there is a risk that other lines will become overloaded. The *system protection* will disconnect production so that the lines will be relieved. The signals originate from Grundfors, Betåsen, and Hjälta and are sent to stations northwards. The setting of the automated equipment is adapted to the state of operation.
The *system protection* also includes a link with Norway so that the loss of a link between Porjus and Ofoten will lead to *load shedding* in northern Norway.

4.3 Sweden: System protection in the West Coast cross-section (Kilanda-Horred + Stenkullen-Strömma)

During imports from Germany, Zealand and Jutland and a high level of production at Ringhals, simultaneous to exports towards Norway, there is a risk of overloads on the remaining line in the event of a long-term fault on one of the lines.
The *system protection* will work as follows:
- In the event of losing Kilanda-Horred <u>and</u> transmission of more than 500 MW northbound on the line, this will result in a power change of 300 MW on Konti-Skan 2 towards Western Denmark.
- In the event of losing Stenkullen-Strömma <u>and</u> transmissions of more than 500 MW northbound on the line, this will result in a power change of 300 MW on Konti-Skan 2 towards Western Denmark.

These *system protections* do not provide increased capacity, rather they increase the *system security*.

During exports to Jutland, there is a risk that the regional network around Gothenburg will be overloaded in the event of a long–term fault on the Strömma-Lindome line. The sy*stem protection* will function as follows:
In the event of losing Strömma-Lindome, Konti-Skan 2 will be regulated down to 0 if there are exports on the link.

Extended *system protection*:
This protection disconnects ”production” in Zealand through *production shedding*. This will reduce the imports from Zealand which will relieve the West Coast cross-section and provide increased system security. The activation of ”production” in Zealand by the s*ystem protection* will be taken, following agreement between the *Parties* concerned, into and out of operation on the basis of the operational situation.

4.4 Sweden: System protection Forsmark

In the event of a stoppage on either of the lines Forsmark-Odensala (FL4) or Tuna-Hagby, the transformer at Tuna risks becoming overloaded if a fault arises on the remaining line.
The *system protection* will go into operation in the event of a stoppage on one of the mentioned lines. The *system protection* will regulate down the production at Forsmark to unload the transformer.
The *system protection* will work as follows:

- In the event of losing Forsmark-Odensala (FL4) or Tuna-Hagby, G12 will be regulated down if Forsmark G11, G12 and G21 or G22 are in operation, <u>and</u>:

- in the event of losing Forsmark-Odensala (FL4) or Tuna-Hagby, G22 will be regulated down if Forsmark G21, G22 and G11 or G12 are in operation.

4.5 Sweden: System protection Långbjörn

Production at Ångermanälven is fed out via transformations at Långbjörn and Betåsen. In the event of losing a transformation, there is a risk that the other will become overloaded. The *system protection* at Långbjörn will disconnect the Långbjörn-Korsselbränna-Stalon line with its connected production when the link between Kilforsen and Långbjörn is broken (400 kV line Kilforsen-Långbjörn + transformer T1 at Långbjörn).

4.6 Norway: System protection in the Hasle and Flesaker cross-section

During high export levels from southern Norway to Sweden, there is a risk that the loss of a line can bring about overload, voltage or stability problems. In the event of critical losses, the *system protection* must relieve the cross-sections by means of automatic *production shedding* at Kvilldal, Sima, Aurland, Tonstad, Tokke and/or Vinje. The maximum permissible *production shedding* is 1,200 MW and activation will occur as a result of the following events: Loss of Hasle-Borgvik, Tegneby-Hasle, Rød-Hasle, Hasle-Halden, Halden-Skogssäter, Kvilldal-Sylling and Sylling-Tegneby. During these events, the *system protection* has redundancy when measuring high power levels on Hasle-Borgvik, Hasle-Halden, 300 kV Tegneby-Hasle, 300 kV Flesaker-Tegneby and 300 kV Flesaker-Sylling. The *system protection's* setting will depend on the operational situation.

4.7 Norway: System protection in the Nordland cross-section

In the event of a large power surplus in northern and central Norway, there is a risk of *network collapse* in the event of losing critical lines. The *system protection* must rapidly relieve the cross-section by means of automatic *production shedding* or through network division so that the *surplus area* is separated from the rest of the *synchronous system*. The largest permissible *production shedding* is 1,200 MW.
The *system protection* will be activated by the following events:
- The loss of Ofoten-Ritsem, Ritsem-Vietas, Vietas-Porjus, Ofoten-Kobbelv or Svartisen-N.Røssåga.
- High levels of current on 300 kV Tunnsjødal-Verdal, 300 kV Tunnsjødal-Namsos or 300 kV Nea-Järpströmmen.
The *system protection's* setting will depend on the operational situation and can result in *production shedding* at Vietas, Ritsem, Kobbelv and/or Svartisen. Loss of the lines Ofoten-

Ritsem-Vietas-Porjus might also lead to network division south of Kobbelv. The *system protection* is also described under point 4.2.

4.8 Norway: Local system protection at Kvilldal

Automatic *load shedding* at Kvilldal when the loss of a line entails high levels of transmission westbound (towards Saurdal).

4.9 Norway: Network division in southern Norway

Automated systems that establish separate operation for the southern Norway area during simultaneous stoppages on both the links between southern Norway and Sweden.

4.10 Norway: System protection for load shedding

System protection which disconnects up to 220 MW of industrial load in the event of the loss of one or both 300 kV lines in the Sauda cross-section which supplies Bergen and important industrial centres in Vestlandet.
System protection which disconnects 150 MW or 400 MW of industrial load in the event of the loss of one or two 300 kV lines adjacent to Møre or in the event of loss of lines which entails a low voltage or overload on the Nea-Järpströmmen line. The network supplies general consumption and important industrial centres in Nord-Vestlandet.
System protection which disconnects up to 110 MW of industrial load in the event of losing the 420 kV lines north of Ofoten. The *system protection* will prevent overloads in the parallel 132 kV network which might otherwise lead to a collapse in the most northerly part of Norway.

4.11 Norway: System protection at Sørlandsnittet (PFK and HVDC control)

During abundant exports from Southern Norway to Denmark and with simultaneous low local production, there is a risk of loss of a line, which can lead to overload or voltage problems. During a critical loss of a line, the *system protection* will relieve the cross-section through automatic downward regulation of the Skagerrak HVDC line. The *system protection* measures overload on the 300 kV lines at 4 stations. The *system protection* regulates 400 MW of exports down on Pole 3 during 1 sec.

During abundant imports to Southern Norway from Denmark and with simultaneous high local production, there is a risk of loss of a line, which can lead to overload or voltage problems. During a critical loss of a line, the *system protection* will relieve the cross-section through automatic downward regulation of the Skagerrak HVDC line or PFK at Tonstad. The *system protection* measures overload on the 300 kV lines at 3 stations. The *system protection* regulates 300 MW of imports down on Pole 3 during 1 sec and/or regulates production down at the Tonstad power plant (4 x 160 MW available).

4.12 Western Denmark: Konti-Skan pole 2

The *system protection* on Konti-Skan 2 will be activated at a load of over 80 % of the 400 kV transformer at the Nordjylland plant (NVV3+NNV5) (see point 1 in Figure 6). Transmissions on pole 2 will be reduced until the load is once again under 80 % of the transformer (30 MW per sec.).

The *system protection* is used to increase the import capacity from Sweden (load flow).

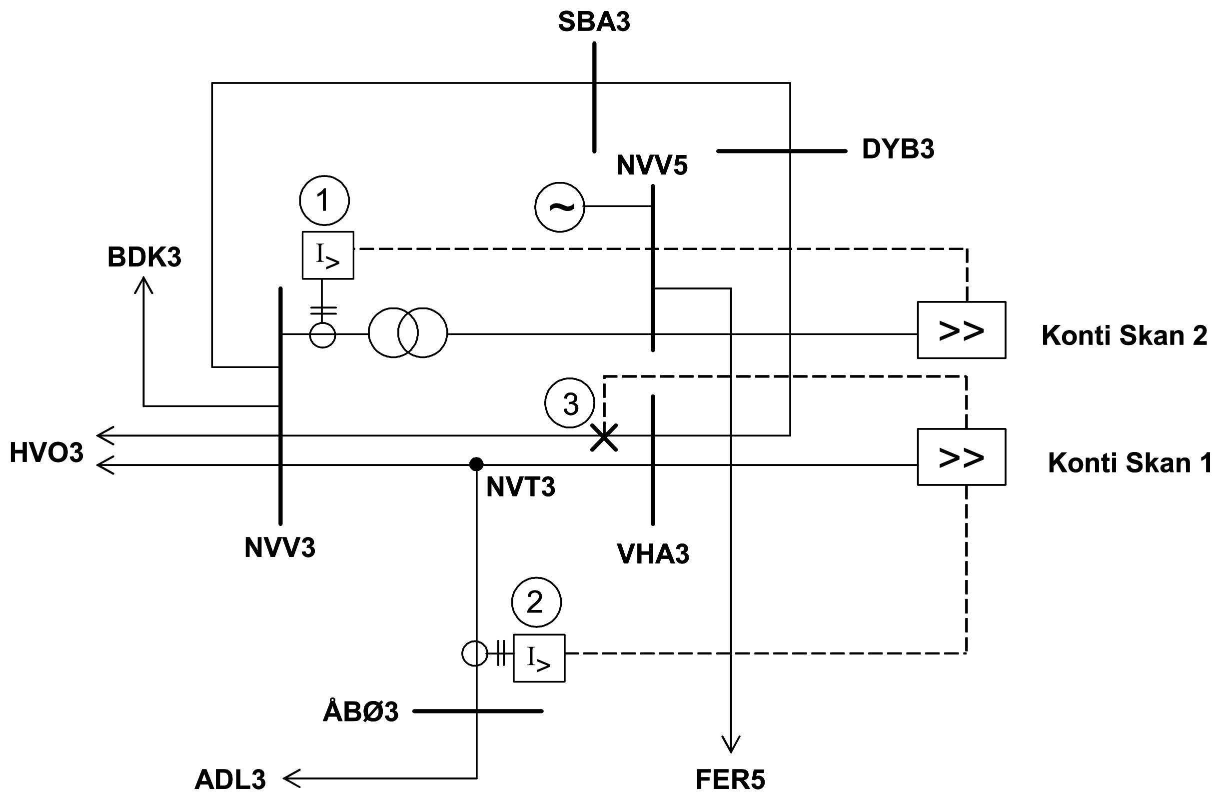

Figure 6 System Protection on Konti-Skan

4.13 Western Denmark: Konti-Skan pole 1 & 2

To safeguard the 150 kV link Ålborg Øst (ÅBØ3) – the Nordjylland plant (NVV3) from dangerous overloads, there is an overload protector at the Ålborg Øst (ÅBØ3) station which disconnects the T-branch (NVT3) - Ålborg Øst (ÅBØ3) during loads of over 150 % for 2-5 minutes. Additionally, the 150 kV line Ådalen (ADL3) - Ålborg Øst (ÅBØ3) is disconnected if the overload exceeds 174 %.

The *system protection* is used to increase the import capacity from Sweden (load flow).

4.14 Western Denmark: Skagerrak pole 3

In the event of a disconnection of the 400 kV line Tjele – Askaer and the 400 kV line Askaer - Revsing - Kassö, imports are reduced from Skagerrak pole 3 to 50 MW.

The *system protection* is not used to increase the import capacity from Norway, only to protect the HVDC station.

4.15 Western Denmark: the German link

In the event of loads on the links to Germany in excess of 120 % for more than 15 seconds, the remote control system will automatically commence downward regulation of the HVDC links.

Regulation will be terminated when transmissions are normal again or when maximum regulation has been reached. The function allows a maximum of 200 MW on Skagerrak poles 1, 2 and 3 as well as 150 MW on each of the Konti-Skan poles.

4.16 Finland: Frequency regulation (during island operation) with automated systems on the HVDC Fenno-Skan link

The *system protection* can be used when the northern AC network between Rauma and Dannebo is broken. This can control the frequency of the potential island network in Finland.

4.17 Finland: Power modulation for Fenno-Skan (Power modulation control)

The *system protection* can be used to attenuate large power oscillations between the countries. Uses the frequency difference between Sweden and Finland as a signal and modulates the power ± 100 MW.

4.18 Finland: Network division in northern Finland to protect the 110 kV network from overloads

The *system protection* sections the line Vajukoski-Meltaus 110kV when the power on the line is over 100 MW for 0.2 seconds.

4.19 Finland: System protection for avoiding system oscillations

The *system protection* is used to increase the capacity in the north towards Sweden. In certain fault scenarios, with large transmission levels, there is a risk of system oscillations. *System protection* relieves transmissions by means of *production shedding* in southern Finland. *Production shedding* is activated by means of remotely-transmitted signals from activated protection functions. Extent approx. 900 MW. The *system protection* is activated automatically depending on the operational situation. The Power System Centre in Helsinki can put *system protection* into/out of operation using the remote control system, depending on the transmission situation.

SYSTEM SERVICES

System services is a generic term for services that the *system operators* need for the technical operation of the power system. The availability of *system services* is agreed upon between the *system operator* and the other companies within the respective *subsystem*.

1 Survey of system services

1.1 System services defined in Appendix 2 of the System Operation Agreement

1.1.1 Frequency controlled normal operation reserve

Activated automatically within a ± 0.1 Hz deviation and shall be regulated out within 2-3 minutes. The joint requirement for the *synchronous system* is 600 MW. This means a joint requirement for *frequency response* in the *synchronous system* of 6,000 MW/Hz.
This service can be exchanged to a certain degree. Each *subsystem* shall have at least 2/3 of the *frequency controlled normal operation reserve* within its own system in the event of splitting up and island operation. A major exchange of the service between the *subsystems* can require a greater need for *regulating margin* (the difference between the *transmission* and *trading capacities*). Elspot exchanges and joint Nordic *balance regulation* take priority over the exchange of *automatic active reserve*. Thus, the exchange of this service is agreed after the Elspot has closed.

TSO	**Generation of system service**	**Exchange between subsystems**
Energinet.dk East	Droop control at thermal power plants.	Yes
Energinet.dk West	No requirement regarding frequency controlled normal operation reserve from UCTE.	
Fingrid	Measured droop control at hydropower and thermal power plants. DC link towards Russia.	Yes Yes
Statnett	% turbine opening/Hz in hydropower.	Yes
Svenska Kraftnät	% turbine opening/Hz in hydropower.	Yes

1.1.2 Frequency controlled disturbance reserve

Activated automatically at 49.9 Hz and fully activated at 49.5 Hz. At least 50 % shall be regulated out within 5 sec and 100 % within 30 sec. Joint requirement for the *interconnected Nordic power system* is approx 1,000 MW, depending on the relevant *dimensioning fault*.

The service is closely linked to *frequency controlled normal operation reserve*, and the principle of exchange is the same.

TSO	**Generation of system service**	**Exchange between subsystems**
Energinet.dk East	Disconnection of district heating. Turbine opening at thermal power plants. Droop control from thermal power plants. HVDC interventions.	Yes
Energinet.dk West	Condensate stoppage at thermal power plants. Droop control (modified gliding pressure) at thermal power plants.	No (only exchanged between Energinet.dk West and UCTE)
Fingrid	Droop control at hydropower and thermal power plants. Sheddable load.	Yes Yes
Statnett	% turbine opening/Hz in hydropower. HVDC interventions, in stages depending on freq	Yes
Svenska Kraftnät	% turbine opening/Hz in hydropower. HVDC interventions, in stages depending on freq. Automatic start-up of gas turbines, in stages depending on freq. Some with 5 sec start-up delay.	Yes

1.1.3 Voltage controlled disturbance reserve

This service becomes relevant when low voltage activates *emergency power* on HVDC links out from the *synchronous system*. The service is applicable to exchanges.

TSO	**Generation of system service**	**Exchange between subsystems**
Energinet.dk East	Not used.	
Energinet.dk West	Not used.	
Fingrid	Not used.	
Statnett	Emergency power Skagerrak.	Yes
Svenska Kraftnät	Automatic export restriction on DC links south of cross-section 4 in Sweden. SwePol Link, Baltic Cable and Kontek (Zealand).	Yes

1.1.4 Fast active disturbance reserve

This service restores *frequency controlled disturbance reserve* and shall be activated within 15 minutes. This service can be exchanged between the *subsystems* of the joint Nordic *regulation market* or as *supportive power.* However, in the event of *power shortages,* Appendix 9 comes into force.

TSO	Generation of system service	Exchange between subsystems
Energinet.dk East	Contract with producer. Gas turbines, upward regulation of rolling reserve, fast-start thermal power plants.	Yes
Energinet.dk West	Contract with producer, bids can be made via regulation market.	Yes
Fingrid	Gas turbines. Sheddable load. Russian DC link.	Yes Yes Yes
Statnett	Contracted regulating power: Options market for regulating power (production and consumption). Voluntary bids on regulation market.	Yes Yes
Svenska Kraftnät	Requirement for producers to report to SvK, gas turbines and hydropower.	Yes

1.1.5 Slow active disturbance reserve

Requirements for each *system operator* to comply with will depend on national legislation. Activation is slower than 15 minutes. The service is not yet relevant to exchanges between the *subsystems*. However, in the event of *power shortages,* Appendix 9 comes into force.

TSO	Generation of system service	Exchange between subsystems
Energinet.dk East	Thermal power plants with a start-up time of up to 4 hours and rearrangement of production types at thermal power plants.	
Energinet.dk West	There are no plants with a start-up time of < 4 hours.	
Fingrid	Power available after 15 minutes, market is responsible.	No
Statnett	Not used	
Svenska Kraftnät	Most frequently replaced by a surplus of fast active disturbance reserve.	No

1.1.6 Reactive reserve

Reactive reserve is of a local nature. Consequently, it cannot be exchanged between the *subsystems*.

TSO	**Generation of system service**	**Exchange between subsystems**
Energinet.dk East	Over/under magnetization of production plants. Synchronous condenser operation in one generator. Connection/disconnection of capacitor batteries and reactors.	No
Energinet.dk West	Over/under magnetization of central production plants. Change of Mvar production at power plants. Synchronous condensers at Tjele and Vester Hassing. Connection/disconnection of capacitors. Connection/disconnection of reactors.	No
Fingrid	Over/under magnetization of production plants. Synchronous condenser operation at certain hydropower plants. Connection/disconnection of power lines. Connection/disconnection of capacitor batteries and reactor.	No No No No
Statnett	Over/under magnetization of production plants. Connection/disconnection of power lines. Connection/disconnection of capacitor batteries. Static phase compensation (SVC plants).	No
Svenska Kraftnät	Over/under magnetization of production plants. Connection/disconnection of power lines. Connection/disconnection of capacitor batteries, reactors. Static phase compensation (SVC plants).	No

[1]) Payment for production of reactive power in generators outside certain limits for tanφ.

1.2 System services not defined in Appendix 2 of the System Operation Agreement

1.2.1 Load following

Load following entails that *players* with major production changes report production plans with a resolution of 15 minutes. *Load following* with a quarter-hourly resolution improves the quality of the frequency of the *synchronous system*. This service can be exchanged between the *subsystems*.

TSO	**Generation of system service**	**Exchange between subsystems**
Energinet.dk East	Not used.	
Energinet.dk West	Production balance centres with variable production deliver running schedules with a resolution of 5 min.	Partly, 5 min and 15 min. plans are sent to other TSOs
Fingrid	Hour shift regulation. Balance centres inform Fingrid about hours containing more than 100 MW of changes in their balance.	Yes[1]
Statnett	Players with major production changes make their production plans using a quarter-hourly resolution. Statnett can move planned production changes for all players by up to 15 minutes.	Yes[1] Yes[1]
Svenska Kraftnät	Players report production plans with a quarter-hourly resolution to SvK. SvK has the right to move production by at least a quarter of an hour.	Yes[1]

[1]) Quarter hourly regulation improves the quality of the frequency throughout the synchronous system.

1.2.2 System protection

The service is exchanged to some degree today. It is imaginable that the Nordic power system will become more integrated in the future. Then, events in one *subsystem* will be able to activate *system protection* in another *subsystem*.

TSO	**Generation of system service**	**Exchange between subsystems**
Energinet.dk East	Automatic downward regulation and/or disconnection of power plants and/or KONTEK, automatic upward regulation of KONTEK. Specified in App. 5.	No
Energinet.dk West	Emergency power on Kontiskan and Skagerrak. Downward regulation of Kontiskan in the event of an overload on transformers. Downward regulation of Skagerrak 3 upon the loss of some 400 kV lines (downward regulation in respect of voltage quality).	Yes
Fingrid	Automatic production shedding. Network division. Specified in App 5.	No
Statnett	Automatic disconnection of power plants and smelting works. Emergency power on Skagerrak.	Yes Yes
Svenska Kraftnät	Automatic downward regulation of SwePol link, Baltic Cable and Kontek.	Yes

1.2.3 Ramping

Ramping entails a *system operator* designating a facility for complete or partial regulation in step with the HVDC links, when it is being regulated on an HVDC link out from the *synchronous system*. This is a *system service* for improving the quality of the frequency and for allowing major load changes on the HVDC links. This service can be exchanged between the *subsystems*.

TSO	Generation of system service	Exchange between subsystems
Energinet.dk East	Not used.	
Energinet.dk West	Not used.	
Fingrid	Not used.	
Statnett	Not used.	
Svenska Kraftnät	Not used.	

1.2.4 Black starts

This service is of a local nature. Consequently, it cannot be exchanged between the *subsystems*.

TSO	Generation of system service	Exchange between subsystems
Energinet.dk East	Diesel generator and/or gas turbines.	No
Energinet.dk West	2 gas turbines.	No
Fingrid	Some hydropower plants and gas turbines.	No
Statnett	Some selected hydropower plants.	No
Svenska Kraftnät	Some selected hydropower plants.	No

1.2.5 Automatic load shedding

This service is relevant during major *operational disturbances*. The *subsystems* will then hardly be interconnected and the service will not be relevant to exchanges.

TSO	Generation of system service	Exchange between subsystems
Energinet.dk East	Frequency controlled load shedding and disconnection of links between Sweden and Zealand. Specified in App. 5.	No
Energinet.dk West	Load shedding. Link with Germany is not disconnected. Load shedding between 48.7 Hz and 47.7 Hz.	No
Fingrid	Automatic load shedding between 48.7 Hz – 48.3 Hz.	No
Statnett	Automatic load shedding between 49.0 Hz – 47.0 Hz.	No
Svenska Kraftnät	Automatic load shedding between 48.8Hz – 48.0 Hz.	No

1.2.6 Manual load shedding

This service is used during major *operational disturbances* and *power shortages* and cannot be exchanged between the *subsystems*. This is regulated by Appendix 9.

TSO	Generation of system service	Exchange between subsystems
Energinet.dk East	The load can be shed to eliminate non-approved transmissions on the network, for managing power shortages, during island operation and when automatic shedding has not been sufficient.	No
Energinet.dk West	The load can be shed to eliminate non-approved transmissions on the network, for managing power shortages, during island operation and when automatic shedding has not been sufficient.	No
Fingrid	Sheddable load used as fast active disturbance reserve, can also be used during power shortages when only 600 MW of fast active disturbance reserve remains in the synchronous system.	No
Statnett	Used during power shortages when only 600 MW of fast active disturbance reserve remains in the synchronous system.	No[1]
Svenska Kraftnät	Used during power shortages when only 600 MW of fast active disturbance reserve remains in the synchronous system.	No

[1]) No particular compensation is paid to the players. However, when the service is activated, Statnett will obtain the CENS (Compensation for Energy Not Supplied) liability, entailing a reduction of the revenue limit.

1.2.7 Fast active forecast reserve

This service restores the *frequency controlled normal operation reserve*. Using this, deviations in consumption and/or production forecasts are adjusted. Requirements for each *system operator* to comply with will depend on national legislation. Activation time is 10-15 min.
The service is exchanged between the *subsystems* in the joint Nordic *regulation market* as voluntary or contracted *regulation power*, but in the event of *power shortages,* Appendix 9 will come into force.

TSO	Generation of system service	Exchange between subsystems
Energinet.dk East	Contract with producers regarding bids (as bids in the regulation market).	Yes
Energinet.dk West	Contract with producers regarding minimum bids (as bids in the regulation market). Voluntary bids in the regulation market.	Yes Yes
Fingrid	Voluntary bids in the regulation market.	Yes
Statnett	Contracted regulation power: Options market for regulation power (production and consumption). Voluntary bids in the regulation market.	Yes Yes
Svenska Kraftnät	Voluntary bids in the balance regulation (secondary regulation).	Yes

1.2.8 Fast active counter trading reserve

Requirements for each *system operator* to comply with will depend on national legislation. The service can be exchanged between the *subsystems* during the *operational phase*.

TSO	Generation of system service	Exchange between subsystems
Energinet.dk East	Particular purchases from producers.	
Energinet.dk West	Particular purchases from producers and bids in the regulation market can be used.	Yes
Fingrid	Voluntary bids in the regulation market can be used.	Yes
Statnett	Contracted regulation power: Options market for regulation power (production and consumption). Voluntary bids in the regulation power market.	Yes Yes
Svenska Kraftnät	Voluntary bids in the balance regulation (secondary regulation).	Yes

1.2.9 Peak load resource

Requirements for each *system operator* to comply with will depend on national legislation.
By *peak load resource* is meant active reserve which is not normally used. For anticipated peak load periods, the preparedness time is reduced so that the capacity, as and when needed, can be used. The service can be exchanged between the *subsystems* in the joint Nordic *regulation market*. However, in the event of *power shortages,* Appendix 9 will come into force.

TSO	Generation of system service	Exchange between subsystems
Energinet.dk East	Not used.	
Energinet.dk West	Not used.	
Fingrid	Not used.	
Statnett	Not used.	
Svenska Kraftnät	Being procured.	

2 Description of routines for trading in system services

2.1 General

Trading in *system services* shall not be an obstacle to either *Elspot trading* or *balance regulation*.

2.2 Trading in frequency controlled normal operation reserve and frequency controlled disturbance reserve

Trading in *frequency response* can be simultaneously trading in *frequency controlled normal operation reserve* and *frequency controlled disturbance reserve* depending on how the individual services are acquired in the separate *subsystems*.

During conversion between the *frequency response*, *frequency controlled normal operation reserve* and *frequency controlled disturbance reserve,* the following conversion table is to be used, unless otherwise agreed:

Frequency response	Frequency controlled normal operation reserve	Frequency controlled disturbance reserve
10 MW	1 MW	1.5 MW

System operators can inform each other on a daily basis after the Elspot has closed regarding surpluses of *frequency response* that can be offered to the other *system operators*.

System operators that have a need to purchase can contact the relevant *system operator* to obtain information on prices and volumes.

When the total purchasing requirement is larger than the supply, distribution shall take place on the basis of the basic requirement for the *frequency controlled normal operation reserve*.

Trading is carried out bilaterally between *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.

2.3 Exchanges using other types of reserves

Services linked to the joint Nordic *regulation market* are described in Appendix 3.

JOINT OPERATION BETWEEN THE NORWEGIAN AND SWEDISH SUBSYSTEMS ON THE AC LINKS

1 Background

The *subsystems* of Norway, Sweden, Finland and Eastern Denmark are synchronously interconnected. The *subsystem* of Western Denmark is connected to Norway and Sweden using DC links. This Appendix describes the operation of the AC links between the *subsystems* of Sweden and Norway.

2 Transmission facilities linking the subsystems of Sweden-Norway

2.1 Transmission facilities which are owned/held by system operators at both ends

Facility	Voltage kV	Settlement point	Misc.
Ofoten-Ritsem	400	Ritsem	
N.Rössåga-Gejmån-Ajaure	220	Gejmån, Ajaure	
Nea-Järpströmmen	300	Nea	
Hasle-Borgvik	400	Hasle	Incl. in Hasle cross-section
Halden-Skogssäter	400	Halden	Incl. in Hasle cross-section

2.2 Other transmission facilities

Sildvik-Tornehamn	130	Tornehamn	Vattenfall owner on Swedish side

2.3 Other transmission facilities than those under 2.2

Eidskog-Charlottenberg	130	Charlottenberg	Fortum owner on Swedish side

This *transmission facility* is not included in the grid on the Swedish side. The *trading capacity* of the link is submitted to Nord Pool by Statnett on the Norwegian side and by Fortum on the Swedish side.

3 Electrical safety for facilities under 2.1

3.1 General

The common ground for the electrical safety work of the *system operator* companies within Nordel is constituted by the European standard for managing electrical high-voltage facilities EN 50 110 which governs the organisation and working methods. In addition to the standard, there are national regulations and special instructions which entail certain mutual differences between the *system operators* as regards dealing with operational issues from an electrical safety point of view.

3.2 Responsibility for electrical operation/Operational management

Responsible for the electrical operation of the facility on the Swedish side is Svenska Kraftnät, while on the Norwegian side it is Statnett. The *power operation responsibility boundaries* for electrical operation for facilities under 2.1 lie at the national border between Sweden and Norway.

3.3 Switching responsible operator

For each of the cross-border links, there is a specific switching agreement between the parties.

Line	Norway	Sweden
Ofoten-Ritsem	Regional Centre at Alta	Operations Centre at Sollefteå (DCSO)
N.Rösståga-Gejmån-Ajaure	Regional Centre at Sunndalsöra	Operations Centre at Sollefteå (DCSO)
Nea-Järpströmmen	Regional Centre at Sunndalsöra	Operations Centre at Sollefteå (DCSO)
Hasle-Borgvik	Regional Centre in Oslo	Operations Centre at Råcksta (DCRÅ)
Halden-Skogssäter	Regional Centre in Oslo	Operations Centre at Råcksta (DCRÅ)

3.4 Operations monitoring and control in respect of electrical safety

Same *Parties* as under 3.3.

3.5 Switching schedule

Switchings on the links are carried out in accordance with a switching schedule drawn up by Svenska Kraftnät. Statnett's Regional Centres acknowledge reception.

3.6 Disturbance management

3.6.1 Cross-border link trips – management

During *operational disturbances*, measures in accordance with issued instructions shall as soon as possible restore the link to *normal state*.

3.6.2 Switching schedule

In the event of faults needing switchings which will affect the *cross-border link,* Statnett and Svenska Kraftnät are to be informed before any switchings are made. In the case of switchings on the Swedish grid, switching schedules are to be drawn up by Svenska Kraftnät.

3.6.3 Fault finding

Initial fault finding will be carried out differently from case to case. Generally speaking, the respective facility owner will be responsible for fault finding in consultation with the switching responsible operator.

3.6.4 Fault clearance, remaining faults

Once the fault has been localized, the respective facility owner will attend to clearing the fault.

4 System operation for facilities under 2.1 and 2.2

4.1 Transmission capacity (TTC)

The *transmission capacity* of the links is as follows, in MW.

Line	-20 °C	-10°C	0°C	10°C	20°C	30°C	Total to Sweden	Total to Norway
Sildvik – Tornehamn (to Sweden)	120	120	120	120	120	100	Approx 900-1,300	Approx 700-1,100
Sildvik – Tornehamn (from Sweden)	70	70	70	70	70	70		
Ofoten – Ritsem	1,350	1,350	1,350	1,350	1,170	880		
N.Rösslåga - Gejmån –Ajaure	536	496	451	398	334	250		
Nea - Järpströmmen	730	690	650	610	550	500		
Hasle -Borgvik	2,100	2,000	1,900	1,780	1,650	1,510	See below	See below
Halden – Skogssäter	3,070	2,900	2,700	2,490	2,260	2,000		

The *transmission capacity* is limited by defined *transmission cross-sections*, stability conditions or similar. The *transmission capacity* thus varies in accordance with how it is distributed between the links.

- To Norway in the Hasle cross-section: The *transmission capacity* is dependent on the temperature as follows (at temperatures below 0ºC, the transmission capacity is restricted by voltage in Sweden):

Temperature [°C]	-20	-10	0	10	20	30
Capacity [MW]	2,150	2,150	2,150	2,150	2,050	1,900

- To Sweden in the Hasle cross-section: The *transmission capacity* is 1,600 MW without *production shedding*. For every 100 MW of production, *production shedding* increases the *transmission capacity* by 50 MW. The maximum *production shedding* is 1,200 MW, corresponding to 2,200 MW of capacity.

The *transmission capacity* will be reduced due to a high Oslo load, in accordance with the following table:

Oslo load [MW]	3,200	3,300	3,400	3,500	3,600	3,700	3,800	3,900	4,000	4,100
Capacity [MW]	2,200	2,175	2,090	2,000	1,900	1,785	1,700	1,600	1,450	1,250

Oslo load [MW]	4,200	4,300	4,400	4,500	4,600	4,700	4,800	4,900	5,000
Capacity [MW]	1,050	850	650	500	350	200	100	50	0

4.2 Routines for determining the transmission capacity

The *transmission capacity* between Norway and Sweden shall be jointly determined on a daily basis by the *Parties*.

4.3 Trading capacity (NTC)

When determining the *trading capacity* of the links, the *transmission capacity* shall be reduced by the *regulating margin*.

The *regulating margin* of the Hasle cross-section is normally 150 MW. The total *regulating margin* of the other links is normally 50 MW.

If a country can guarantee *counter trading* and the existence of a sufficient *fast active disturbance reserve*, then the *trading capacity* may be increased.

For the *trading capacity,* a weekly forecast is established for the coming week. The forecast is sent to Nord Pool by at the latest the Tuesday of the week before.

4.4 Operation monitoring and control in respect of system operation

Operation monitoring of capacities and *transmission cross-sections*, which can affect exchanges, are conducted in accordance with the below:

Line	Norway	Sweden
Sildvik-Tornehamn	National Centre in Oslo	Vattenfall Norrnät's Operations Centre at Luleå
Ofoten-Ritsem	National Centre in Oslo	SvK's Grid Supervisor at Network Control at Råcksta
N.Rösståga-Gejmån-Ajaure	National Centre in Oslo	SvK's Grid Supervisor at Network Control at Råcksta
Nea-Järpströmmen	National Centre in Oslo	SvK's Grid Supervisor at Network Control at Råcksta

Hasle-Borgvik	National Centre in Oslo	SvK's Operations Centre at Råcksta
Halden-Skogssäter	National Centre in Oslo	SvK's Grid Supervisor at Network Control at Råcksta

4.5 Voltage regulation

The basic principle for voltage regulation is governed by item 7 point 7.5 in the agreement.

4.5.1 Voltage regulation on the Norwegian side

Voltage is monitored by the National Centre in Oslo and Regional Centres in Alta, Sunndalsöra and Oslo. If the Regional Centres do not have sufficient resources to maintain the voltage within the given limits, the National Centre will be contacted.

The following voltage levels are applied:

Substation	Min voltage kV	Normal operation range kV	Max voltage kV
Ofoten	400	400-415	425
Nedre Rösslåga	235	240-250	250
Nea	285	285-300	306
Hasle	380	410-415	430
Halden	380	410-415	430

4.5.2 Voltage regulation on the Swedish side

The Operations Centre in Sollefteå (DCSO) is responsible for voltage regulation in the northern parts of the grid, and the Operations Centre in Råcksta (DCRÅ) is responsible for voltage regulation in the southern parts of the grid. If the Operations Centres do not have sufficient resources to maintain the voltage within the given limits, SvK's Operations Centre shall be contacted.

The following voltage levels are applied:

Substation	Min voltage kV	Normal operation range kV	Max voltage kV
Ritsem	395	400-415	420
Ajaure	230	245-255	260
Järpströmmen	280	285-295	305
Borgvik	395	400-415	420
Skogssäter	395	400-415	420

4.5.3 Co-ordination of voltage regulation

In normal operation, the goal is the higher voltage within the normal operation range. In conjunction with operational disturbances and switching, the respective operations centres in Sweden and Norway can agree on action to maintain the voltage within the given intervals.

4.6 Outage planning

Svenska Kraftnät shall plan the following in consultation with Statnett:

- Outages or other measures on the Swedish network impacting upon the *transmission capacity* of the links between Sweden and Norway.
- Outages on one of the 400 kV lines between Porjus and Ritsem.
- Outages on the 400 kV line between Midskog and Järpströmmen or the 400/300 kV transformer at Järpströmmen.
- Outages on one of the 220 kV lines between Grundfors and Gejmån or the 400/220 kV transformer at Grundfors.
- Outages causing a major reduction of the *transmission capacity* in cross-sections 1 or 2, or the West Coast cross-section in Sweden.
- Control facility works at Skogssäter, Borgvik, Porjus, Ritsem and Vietas.

Statnett shall plan the following in consultation with Svenska Kraftnät:

- Outages or other measures on the Norwegian network impacting upon the *transmission capacity* of the links between Sweden and Norway.
- Outages entailing that, on the Norwegian network, there is no link between Ofoten and Rössåga.
- Outages entailing that, on the Norwegian network, there is no link between Rössåga and Nea.
- Outages entailing that, on the Norwegian network, there is no link between Nea and Hasle.

4.7 Disturbance situation

The term disturbance situation means that the *transmission capacities* have been exceeded due to, for instance, long-term line faults or the loss of production. If the *transmission capacities* are not exceeded during the faults, the situation will be deemed to be normal.

In the event of *operational disturbances,* measures in accordance with the issued instructions shall, as soon as possible, restore the link to *normal state*.

JOINT OPERATION BETWEEN THE FINNISH AND SWEDISH SUBSYSTEMS ON THE AC LINKS AND FENNO-SKAN

1 Background

The *subsystems* of Norway, Sweden, Finland and Eastern Denmark are synchronously interconnected. The *subsystem* of Western Denmark is connected to Norway and Sweden using DC links. This Appendix describes the operation of the AC links and the Fenno-Skan DC link.

2 Transmission facilities linking the subsystems Sweden – Finland

2.1 Transmission facilities which are owned/held by system operators

Facility	Voltage level	Settlement point:
Petäjäskoski - Letsi	400 kV AC	Letsi 400 kV
Keminmaa - Svartbyn	400 kV AC	Svartbyn 400 kV
Fenno-Skan	400 kV DC	Dannebo 400 kV
Ossauskoski – Kalix*)	220 kV AC	Kalix 220 kV

*) SvK and Fingrid own the line, Vattenfall Norrnät and Fingrid are responsible for its electrical operation.
The transmissions depend on consumption in the Kalix region. The transmissions are taken into account when determining the trading capacity between Finland and Sweden.

3 Electrical safety for facilities under 2.1

3.1 General

The common ground for the electrical safety work of the *system operator* companies within Nordel is constituted by the European standard for managing electrical high-voltage facilities EN 50 110 which governs the organisation and working methods. In addition to the standard, there are national regulations and special instructions which entail certain mutual differences between the *system operators* as regards dealing with operational issues from an electrical safety point of view.

3.2 Responsibility for electrical operation/Operational management

The responsibility for electrical operation for the *transmission facilities* is held in Finland by Fingrid. In Sweden, SvK holds the responsibility for electrical operation.

The *power operation responsibility boundary* concerning the 400 kV links lies at the border between Finland and Sweden. The *power operation responsibility boundary* regarding Fenno-Skan lies at the cable connection point in the terminal at Rihtniemi, Finland.

3.3 Switching responsible operator

Facility	**Swedish side**	**Finnish side**
Petäjäskoski – Letsi	Operations Centre at Sollefteå (DCSO)	Tavastehus Network Centre
Keminmaa - Svartbyn	Operations Centre at Sollefteå (DCSO)	Tavastehus Network Centre
Fenno-Skan	Operations Centre at Råcksta (DCRÅ)	Tavastehus Network Centre

3.4 Operations monitoring and control in respect of electrical safety

Operations monitoring and control in Finland are carried out from:

– Tavastehus Network Centre as regards the AC links and Fenno-Skan.

Operations monitoring and control in Sweden are carried out from:

– The Operations Centre at Sollefteå (DCSO) as regards the 400 kV AC links.

– The Operations Centre at Råcksta (DCRÅ) as regards Fenno-Skan.

3.5 Switching schedule

Switchings on the links are carried out in accordance with a switching schedule drawn up by Svenska Kraftnät.

3.6 Disturbance management

When a *cross-border link* is taken out of operation, the control rooms will contact each other immediately.

As and when required, the switching responsible operators issue the necessary switching schedules in order to carry out fault finding and clearance.

The switching responsible operators conduct fault finding in consultation.

Clearance of remaining faults is organised by the switching responsible operators in consultation.

For Fenno-Skan, the Preparedness plan for fault clearance is used.

4 System operation for facilities under 2.1

4.1 Transmission capacity (TTC)

4.1.1 400 kV AC links

The *transmission capacity* to Finland is dependent upon the temperature in northern Sweden and Finland, as follows:

Temperature °C	< 20	> 20
Capacity	1,650 MW	1,600 MW

The *transmission capacity* to Sweden is limited because of dynamic reasons as follows:

Cross-section 1	Max. transmission to Sweden
3,000 MW	1,200 MW
3,100 MW	1,100 MW
3,300 MW	1,000 MW

The *transmission capacity* of only one 400 kV link in the north is a maximum of:

	Planned outage in the other link	Disturbance in the other link
To Finland	700 MW	500 MW
From Finland	400 MW	400 MW

4.1.2 Fenno-Skan

The *transmission capacity* of Fenno-Skan is transiently max. 600 MW. The *transmission capacity* of Fenno-Skan is temperature-dependent, the normal value being 550 MW. As the *trading capacity,* a temperature-dependent value is used continuously, normally 550 MW.

4.2 Routines for determining the transmission capacity

The *transmission capacity* between the *subsystems* is set on a daily basis in consultation between the System Operation Centre in Helsinki and SvK's Grid Supervisor at Network Control at Råcksta.

Both parties shall inform the other *party* in good time before the day of operation of the *transmission capacity* on Fenno-Skan and on the northern links. The minimum values will be the *transmission capacity.*

4.3 Trading capacity (NTC)

When determining the *trading capacity* of the AC links, the *transmission capacity* is reduced by a *regulation margin* of 100 MW. Consumption in the Kalix region is taken into account when determining the *trading capacity* between Finland and Sweden. The *trading capacity* of Fenno-Skan is equal to its *transmission capacity*, normally 550 MW. For the *trading capacity,* a weekly forecast is set for the coming week. The forecast is sent to Nord Pool by at the latest the Tuesday of the week before.

4.4 Operations monitoring and control in respect of system operation

Operations monitoring and control in Finland are carried out from:

- The System Operation Centre in Helsinki as regards AC links and Fenno-Skan.

Operations monitoring and control in Sweden are carried out from:

- SvK's Grid Supervisor at Network Control at Råcksta concerning 400 kV AC links and Fenno-Skan.

Regulation of Fenno-Skan is carried out on an alternating basis per half calendar year: the first half by Svenska Kraftnät's Operations Centre at Råcksta and the second half by the System Operation Centre in Helsinki.

4.5 Voltage regulation

The basic principle for voltage regulation is governed by item 7 point 7.5 in the agreement.

4.5.1 Voltage regulation on the Swedish side

The Operations Centre in Sollefteå (DCSO) is responsible for voltage regulation in the northern parts of the grid.

The following voltage levels are applied:

Substation	Min voltage kV	Normal operation range kV	Max voltage kV
Letsi	395	400-410	415
Svartbyn	395	400-415	420

The minimum voltage is a voltage which the power system can withstand with a certain margin against a voltage collapse. The maximum voltage is the design voltage of the equipment. The target value for voltage lies within the normal operation range.

4.5.2 Voltage regulation on the Finnish side

For voltage regulation, there are reactors on the tertiary windings of transformers and capacitors in the 110 kV system.

At Keminmaa, the capacitor is connected for reactive power on the 110 kV side of transformers. The reactors are connected by means of automation for 400 kV voltages. The automation has three windows of +/- 4 kV and it can be adjusted upwards and downwards from the System Operation Centre.

At Petäjäskoski, the reactors are connected manually.

The following voltage levels are applied:

Substation	Min voltage kV	Normal operation range kV	Max voltage kV
Petäjäskoski	380	400-417	420
Keminmaa	380	399-417	420

4.5.3 Co-ordination of voltage regulation

Problems can arise on the Svartbyn - Keminmaa line if the Swedish side does not pay attention to the Finnish voltage regulation principle. There can be consequential impacts between reactor connections at Svartbyn and corresponding connections at Keminmaa on account of the size of the reactor at Svartbyn, 150 Mvar. The voltage at Svartbyn shall be held within 406 - 414 kV. If problems occur, the relevant parties shall contact each other.

4.6 Outage planning

The *Parties* shall plan, in consultation with each other, outages on the links and on their own networks when such outages will impact upon the *transmission capacities* of the links.

Planned outages on Fenno-Skan are to be co-ordinated with the other HVDC links of the Nordic area.

4.7 Disturbance management

The term disturbance situation means that the *transmission capacity* has been exceeded due to, for instance, long-term line faults or the loss of production. If the *transmission capacity* has not been exceeded during the faults, the situation will be deemed normal.

When a *cross-border link* is disconnected, the control rooms will immediately contact each other and jointly reduce the transmission level to permissible values.

During hours when a disturbance situation is in force, loss minimization is not employed. This means that no compensation for loss minimization benefit will be paid out. The *Parties* will only pay for non-notified *balance power*.

During disturbance situations, both *Parties* have the right to regulate Fenno-Skan to support their networks. Fenno-Skan can be used as much as possible facility-wise and to an extent not entailing any difficulties in the other *Party's* network.

During a disturbance situation, the *Parties* shall immediately contact each other and agree that it is a disturbance situation. In conjunction with this, it must also be agreed how much Fenno-Skan is to be regulated and who will regulate. If the situation is very serious and the situation in the other *Party's* network can be assumed to be normal, then Fenno-Skan can be regulated by the *Party* affected by the disturbance without any previous contact. Such unilateral regulation may not, however, exceed 300 MW counted from the current setting.

If Fenno-Skan's *emergency power* regulation has been activated, this will also be deemed to be a disturbance situation. If the *emergency power* intervention entails *counter trading* requirements for a *Party* not being affected by a disturbance, then Fenno-Skan shall be regulated within 15 minutes to such a value that the *counter trading* requirement ceases.

5 Distribution of capacity utilization between Finland and Sweden

The distribution of capacity utilization on the cross-border links is governed by a separate agreement between Fingrid and Svenska Kraftnät. The main principles are as follows:

The transmission capacity of the cross-border links is defined for the AC links in the north and for Fenno-Skan. The transmission capacity shall be determined continuously by the parties in accordance with the relevant technical conditions of the System Operation Agreement. The trading capacity is determined by calculating the transmission capacity minus determined regulating margin.

5.1 Basic distribution

Basic distribution is used as a starting point for the distribution of electricity transmissions between northern and southern links. Basic distribution is determined by the proportion between the determined *trading capacity*, at any one given time, of the AC links and Fenno-Skan 1. Basic distribution shall be used if neither loss minimization nor the use of the other *Party's* idle capacity is relevant.

Basic distribution is applied as follows:

– For each hour, the planned cross-border power trade is totalled.

– The power trade is distributed between the northern AC links and Fenno-Skan in accordance with the above basic distribution.

– Elbas and *supportive power* trading across the border are not handled in basic distribution.

If either *Party* needs to limit the AC links or Fenno-Skan due to internal limitations, e.g. cross-sections 1, 2 or P1, the above trading capacity will nevertheless be used for the AC link and Fenno-Skan when calculating basic distribution.

5.2 Loss minimization (Fenno-Skan optimization)

In the event of loss minimization, Fenno-Skan will be regulated in such a way that the transmission losses on the Finnish and Swedish grids are minimized. The benefits thus gained are to be divided equally between Fingrid and SvK through financial reimbursement twice a year.

5.3 Loss minimization model

The model for loss minimization is based upon SvK and Fingrid calculating their network losses as a function of the transmissions on Fenno-Skan. The curves are calculated using the current operating situation and the constant net trade. The curves are sent to the other company and added in order to obtain the minimum point giving a reference value for Fenno-Skan.

The price of energy used in loss minimization shall be *area price* Sweden in Nord Pool Spot's Elspot market. The *Parties* shall specify the prices in SEK. As of the beginning of 2006, the prices shall be specified in EUR.

5.4 Distribution of benefit

The overall benefit to the system during a period of one hour is defined as the positive difference between the calculated overall loss overheads during basic distribution and during the real reference value. Normally, the minimum point is used as the reference value.

The overall benefit shall be distributed in accordance with the 50/50 principle; both *Parties* shall have equal benefit of loss minimization. The distribution of benefit will be as follows: firstly the overall benefit is calculated as set out above. Following this, Fingrid's benefit is calculated as the difference between its loss overheads during basic distribution and during the real reference value. SvK's benefit is calculated the same way. Subsequently, either of the *Parties* compensates the other *Party* to the extent that SvK's benefit increased/decreased by the compensation is the same as Fingrid's benefit increased/decreased by the compensation.

5.5 Utilizing the other party's idle capacity

Both countries have pledged to internally *counter trade* in the event of transmission limitations on their own networks during *normal state*, this applies during the *operational phase*. *Parties* experiencing problems on their networks due to loss minimization have the right to change, free of charge, the power distribution within the range [basic distribution, optimum]. If there are, nevertheless, bottlenecks in one of the networks, the System Operation Centre in Helsinki and SvK's Grid Supervisor at Network Control at Råcksta shall agree upon the redistribution as follows.

5.5.1 Bottlenecks in Fingrid's network

If there are *bottlenecks* in Fingrid's network and there is idle capacity in SvK's network, the System Operation Centre in Helsinki and SvK's Grid Supervisor at Network Control at Råcksta shall agree upon the utilization of SvK's network in order to relieve Fingrid's transmissions. The agreement must feature the following points:

– new reference values for the northern links and Fenno-Skan

– the transit amount=the volume outside the range [basic distribution, optimum].

Afterwards, Fingrid shall compensate SvK for utilizing SvK's capacity. This compensation will be calculated as the product of the transit price and the transit sum. The transit price is, until further notice, set at SEK 30/MWh unless otherwise agreed between the parties. The transit price shall, however, be adjusted by the parties for each commencing period of two (2) calendar years.

5.5.2 Bottlenecks in SvK's network

If there are *bottlenecks* in SvK's network and there is idle capacity in Fingrid's network, the System Operation Centre in Helsinki and SvK's Grid Supervisor at Network Control at Råcksta shall agree upon the utilization of Fingrid's network in order to relieve SvK's transmissions. The agreement must feature the following points:

- new reference values for the northern links and Fenno-Skan
- the transit amount=the volume outside the range [basic distribution, optimum].

Afterwards, SvK shall compensate Fingrid for utilizing Fingrid's capacity. This compensation will be calculated as the product of the transit price and the transit amount. The transit price is, until further notice, set at SEK 30/MWh unless otherwise agreed between the parties. The transit price shall, however, be adjusted by the parties for each commencing period of two (2) calendar years.

5.5.3 Bottlenecks in both parties' networks

If both parties are experiencing *bottleneck* situations simultaneously, the net trade shall be distributed between the links as in basic distribution. But if the *counter trading* overheads in the parties' networks differ greatly and the control rooms agree upon cost distribution, another type of power distribution can be used.

5.6 Settlement of loss minimization

The compensation of loss minimisation takes place twice a year, at the beginning of January and at the beginning of July, if the parties do not agree upon another procedure. Fingrid makes out the invoice if the parties do not agree otherwise.

The compensation of the use of the other party's idle capacity also takes place twice a year at the same time with loss minimisation compensation.

JOINT OPERATION BETWEEN THE NORWEGIAN, FINNISH AND SWEDISH SUBSYSTEMS IN ARCTIC SCANDINAVIA

1 Background

The *subsystems* of Norway, Sweden, Finland and Eastern Denmark are synchronously interconnected. The *subsystem* of Western Denmark is linked to Norway and Sweden using DC links. This Appendix governs the special circumstances resulting from no separate trade being conducted via the Ivalo-Varangerbotn link. The capacity will instead be included in the trading scope for Nord Pool's Elspot market between Norway-Sweden and Sweden-Finland.

2 Transmission facilities linking the subsystems of Norway-Finland

Transmission facilities owned/held at both ends by *system operators*:

Facility	**Voltage kV**	**Settlement point**
Ivalo-Varangerbotn	220 kV AC	Varangerbotn

3 Electrical safety for facilities under 2

3.1 General

The common ground for the electrical safety work of the *system operator* companies within Nordel is constituted by the European standard for managing electrical high-voltage facilities EN 50 110 which governs the organisation and working methods. In addition to the standard, there are national regulations and special instructions which entail certain mutual differences between the *system operators* as regards dealing with operational issues from an electrical safety point of view.

3.2 Responsibility for electrical operation/Operation management

Responsible for the electrical operation on the Norwegian side is Statnett, while on the Finnish side it is Fingrid. The *power operation responsibility boundary* lies at the border between Finland and Norway.

3.3 Switching responsible operator

Line	Norway	Finland
Ivalo-Varangerbotn	Regional Centre at Alta	Tavastehus Network Centre

3.4 Operations monitoring and control in respect of electrical safety

In accordance with 3.3.

3.5 Switching schedule

Switchings on the links are carried out in accordance with a switching schedule drawn up by the *Party* with the outage requirement. The *Party* drawing up the switching schedule is also the switching responsible operator.

3.6 Disturbance management

3.6.1 Cross-border link trips – management

During *operational disturbances*, measures in accordance with issued instructions shall, as soon as possible, restore the link to *normal state*.

3.6.2 Switching schedule

Same as under 3.5.

3.6.3 Fault finding

Initial fault finding is conducted differently from case to case. Generally speaking, the respective facility owner will be responsible for fault finding.

3.6.4 Fault clearance, remaining faults

Once the fault has been localized, the respective facility owner will attend to clearing the fault.

4 System operation for facilities under 2

4.1 Transmission capacity (TTC)

4.1.1 From Norway to Finland

The *transmission capacity* varies between 50 and 130 MW depending on where the sectioning point in Norway is located and the transmission situation in Finland.

4.1.2 From Finland to Norway

The *transmission capacity* is 100 MW from Finland to Norway.

4.2 Routines for determining the transmission capacity

The exchange of *supportive power* is agreed upon on each separate occasion between Statnett and Svenska Kraftnät and between Fingrid and Svenska Kraftnät.

Statnett manages the transmissions on the *cross-border link* by redistributing production and sectioning in Norway so that the *transmission capacity* is not exceeded. Fingrid confirms the daily *transmission capacity*.

4.3 Trading capacity (NTC)

The *trading capacity* is included in the trading scope of Nord Pool's Elspot market between Norway - Sweden and between Sweden - Finland.

4.4 Operations monitoring and control in respect of system operation

In Finland, *operations monitoring* is carried out from the System Operation Centre in Helsinki. *Control* is carried out from the Tavastehus Network Centre following permission from the System Operation Centre.

In Norway, *operations monitoring and control* are carried out from the Regional Centre at Alta following permission from the National Centre in Oslo.

4.5 Voltage regulation

The basic principle for voltage regulation is governed by item 7 point 7.5 in the agreement.

4.5.1 Voltage regulation on the Norwegian side

At Varangerbotn, the target voltage level is 220 kV in normal operation, but the voltage can range between 205 and 235 kV.

4.5.2 Voltage regulation on the Finnish side

The normal operation range of voltage is 230 – 243 kV, but the voltage can range between 215 and 245 kV. At Utsjoki, there is a stationary reactor of 20 MVA.

4.5.3 Co-ordination of voltage regulation

The link is long and sensitive to voltage variations. The voltage is monitored in co-operation between the relevant control centres.

4.6 Outage planning

Outage planning and maintenance are co-ordinated in conjunction with Fingrid's System Operation Centre in Helsinki/Uleåborg Regional Centre and Statnett's National Centre in Oslo/Operation Centre at Alta.

4.7 Disturbance management

The term disturbance situation means that the *transmission capacities* have been exceeded due to, for instance, long-term line faults or the loss of production. If the *transmission capacities* have not been exceeded during the faults, the situation will be deemed normal.

In the event of disturbances, measures in accordance with issued instructions shall, as quickly as possible, restore the link to *normal state*.

5 Miscellaneous

5.1 Settlement

Settlement of power exchanges between Norway and Finland shall be carried out in accordance wit the following principles:

- Power exchanges via the Ivalo - Varangerbotn line shall, for Statnett's part, be included in the total exchanges between Statnett and Svenska Kraftnät.
- Power exchanges via the Ivalo - Varangerbotn line shall, for Fingrid's part, be included in the total exchanges between Fingrid and Svenska Kraftnät.

Settlement is carried out in accordance with separate bilateral agreements between Statnett and Svenska Kraftnät, and between Fingrid and Svenska Kraftnät.

5.2 Information exchange

Statnett is responsible for Fingrid and Svenska Kraftnät obtaining calendar day forecasts for transmissions on the Ivalo – Varangerbotn line.

JOINT OPERATION BETWEEN THE NORWEGIAN AND WESTERN DANISH SUBSYSTEMS ON THE DC LINKS SKAGERRAK POLES 1, 2 AND 3

1 Background

The *subsystems* of Norway, Sweden, Finland and Eastern Denmark are synchronously interconnected. The *subsystem* of Western Denmark is connected to Norway and Sweden using DC links. This Appendix describes the operation of the DC links between Norway and Western Denmark.

2 Transmission facilities linking the subsystems of Norway-Western Denmark

Facility	Voltage kV	Settlement point
Kristiansand-Tjele SK1, SK2	250 kV DC	Kristiansand 300 kV DC
SK3	350 kV DC	Kristiansand 300 kV DC

Together, SK1, SK2 and SK3 make up the Skagerrak link.

3 Electrical safety for facilities under 2

3.1 General

The common ground for the electrical safety work of the *system operator* companies within Nordel is constituted by the European standard for managing electrical high-voltage facilities EN 50 110 which governs the organisation and working methods. In addition to the standard, there are national regulations and special instructions which entail certain mutual differences between the *system operators* as regards dealing with operational issues from an electrical safety point of view.

3.2 Responsibility for electrical operation/Operational management

The responsibility for electrical operation of the *transmission facilities* is held in Western Denmark by Energinet.dk and in Norway by Statnett. The responsibility for electrical operation is regulated by the operation agreements between Energinet.dk and Statnett.

The *power operation responsibility boundaries* for the links lie on the Danish side of the submarine cable at Bulbjerg in Jutland.

3.3 Switching responsible operator

3.3.1 Switchings

In the event of outages on the HVDC links, there shall be an exchange of written confirmation, before a work authorization can be despatched, between Statnett's Regional Centre in Oslo and Energinet.dk's control room at Tjele stating that the HVDC isolators are open and the line is terminal grounded and blocked against connection.

3.3.2 Switching responsible operator

On the Danish side, the authorization to switch in respect of the switching and switching off of the converter stations is given by Energinet.dk's control room at Skærbæk, while authorization for all switchings and work authorizations on the HVDC side of the facilities is given by the local operational management at Tjele.

On the Norwegian side, Statnett's Regional Centre in Oslo gives the switching authorization, and issues work authorizations on the Norwegian side.

Switchings at the AC facilities are normally carried out from Energinet.dk's control room at Skærbæk and from Statnett's Regional Centre in Oslo. Switchings at the HVDC facilities, once these have been disconnected from the AC network, are carried out from Kristiansand and Tjele.

3.4 Operation monitoring and control in respect of electrical safety

Operation monitoring and control in Western Denmark is carried out from:
- Energinet.dk's control rooms at Skærbæk or Tjele.

Operation monitoring and control in Norway is carried out from:
- Statnett's Regional Centre in Oslo.
- The three poles can be operated individually.

3.5 Switching schedule

Prior to planned outages on the HVDC links, written confirmation shall be exchanged between Statnett's Regional Centre in Oslo and Energinet.dk's control room at Tjele. *Outage planning* for the links will be carried out in accordance with 4.5.

3.6 Disturbance management

Faults entailing the disconnection of links are managed via consultation in accordance with internal instructions. For fault localization and clearance, there is a special preparedness plan for submarine cables.

4 System operation for facilities under 2

4.1 Transmission capacity (TTC)

The *transmission capacity* of the links is dependent on the temperature of the air, cable runway and earth.

SK1, SK2:	Techn. min 10 MW/pole	Nominal (500 + 40) MW
SK3:	Techn. min 13 MW	Nominal 500 MW

4.2 Routines for determining the transmission capacity

The *transmission capacity* between Western Denmark and Norway shall be jointly determined on a routine basis by the *Parties*. In the case of intact connecting networks, the *transmission capacity* will be determined by the thermal capacity of the facilities' components. The thermal overload capability allowed by monitoring equipment shall be capable of being used as and when required in accordance with special instructions. For any limitations to the connecting AC networks, Energinet.dk's control room at Skærbæk is responsible for supportive data on the Western Danish side and Statnett for the equivalent on the Norwegian side.

4.3 Trading capacity (NTC)

The normal *trading capacity* in "bipolar operation":

950 MW from Western Denmark to Norway
1,000 MW from Norway to Western Denmark

The above applies when Kristiansand is the exchange point (50 MW of losses).

The following calendar day's *trading capacity* is decided each day. Similarly, a weekly forecast is established for the coming week's *trading capacity*. The forecast is submitted to Nord Pool Spot by at the latest the Tuesday of the week before. The *trading capacity* can be limited by line work, production in the connection area, overhauls etc.

Both *Parties* inform the other *Party* in good time prior to the relevant calendar day about the *transmission capacity* seen from each respective side. The values that are the lowest will form the basis for determining the *trading capacity*.

4.4 Operation monitoring and control in respect of system operation

Operation monitoring and control in Western Denmark is carried out from:

- Energinet.dk's control room at Skærbæk.

Operation monitoring and control in Norway is carried out from:

- Statnett's National Centre in Oslo.

The three poles can be operated individually.

4.4.1 The power flow and distribution between the poles

The distribution of the power flow between the poles shall be determined on a routine basis by the *Parties* taking into account the minimum electrode currents, loss minimization or other technical circumstances in the poles or on the transmission networks on each respective side.

To minimize losses and electrode currents, the following shall be aimed at during resulting exchanges:

> ≥ 75 MW for > 2 hours, the power is distributed at 42 % on SK1, 2 and 58 % on SK3. Also applies during ”monopole operation”.
>
> < 75 MW, SK3 is used alone.

During special operational circumstances, other types of operation can be agreed upon.

4.4.2 Regulating the link

Regulation of the Skagerrak link in accordance with agreed *exchange plans* will be carried out, until further notice, from the Danish side. Energinet.dk’s control room at Skærbæk is responsible for its own *balance regulation* towards Norway. Regulation is carried out, in principle, in accordance with a power plan using *ramping* transitions between different power levels.

The plans are issued as power plans in whole MW for each 5 min value. The link is regulated in accordance with this power linearly from power value to power value.

The power plan is determined in accordance with the energy and power plan agreements forming the basis for utilizing the Skagerrak link.

Planned power regulation during the *operational phase* is set at max. 30 MW/min.

4.5 Outage planning

Outages on the links and on own networks which affect the *transmission capacity* shall be planned in consultation between the *Parties*.

Planning and maintenance are co-ordinated between the respective operational managements.

Overhaul planning is co-ordinated with the other HVDC links in the Nordic area.

4.6 Disturbance management

4.6.1 General

The Skagerrak link is of great importance to Norway and Denmark, thus outages due to disturbances generally entail major economic losses. In the event of *operational disturbances,* measures in accordance with issued instructions shall, as soon as possible, restore the link to *normal state*.

Automated operational disturbance systems are installed at Kristiansand and Tjele which begin to function during disturbances on the Norwegian or Jutland networks.

4.6.2 Emergency power

Emergency power consists of regulating measures which are initiated manually (*manual emergency power*) or automatically by means of a control signal being transmitted to the converter stations using telecoms.

Both sides have the right to initiate *manual emergency power* in the event of unforeseen losses of production, network disturbances or other *operational disturbances*.

Manual emergency power without previous notice may be activated within 100 MW and 100 MWh/calendar day. Prior to activation over and above this, notification and approval shall occur between Energinet.dk's control room at Skærbæk and Statnett's National Centre in Oslo.

4.6.3 System protection

At the DC facilities, *system protection* is constituted by *emergency power* settings at the converter stations. Activation criteria can be locally measured frequency and voltage or via telecoms based on the supplied signal. In the event of activation, any ongoing normal regulation will be interrupted. Activation over and above the agreed limits and regulation back to plan may not occur until the counterparty has approved this. (See further in Appendix 5 – System protection).

Energinet.dk and Statnett can additionally enter into agreements regarding other types of system services.

5 Miscellaneous

5.1 System services

For the automatic or manual activation of *operation reserves,* the available *transmission capacity* can be used.

The *regulation margin* is maintained following the agreement between the *Parties* taking into account the exchange of system services. The *Parties* have the right to utilize idle *transmission capacity* for the transmission of *system services.* Configuration values, power limits etc are agreed upon bilaterally.

5.2 Settlement

Energinet.dk manages balance settlement.

JOINT OPERATION BETWEEN THE WESTERN DANISH AND SWEDISH SUBSYSTEMS ON THE KONTI-SKAN 1 AND 2 DC LINKS

1 Background

The *subsystems* of Norway, Sweden, Finland and Eastern Denmark are synchronously interconnected. The *subsystem* of Western Denmark is connected to Norway and Sweden using DC links. This Appendix describes the DC links between Sweden and Western Denmark.

2 Transmission facilities linking the subsystems of Sweden - Western Denmark

Facility	Voltage kV
KS1	
Lindome - Vester Hassing	285 kV DC
KS2	
Lindome - Vester Hassing	285 kV DC

Together, KS1 and KS2 make up the Konti-Skan link.
Settlement presently takes place on the AC side at Vester Hassing.

3 Electrical safety for facilities under 2

3.1 General

The common ground for the electrical safety work of the *system operator* companies within Nordel is constituted by the European standard for managing electrical high-voltage facilities - EN 50 110 - which governs the organisation and working methods. In addition to the standard, there are national regulations and special instructions which entail certain mutual differences between the *system operators* as regards dealing with operational issues from an electrical safety point of view.

3.2 Responsibility for electrical operation/Operational management

The responsibility for electrical operation of the transmission facilities is held in Western Denmark by Energinet.dk and in Sweden by Svenska Kraftnät. The responsibility for electrical operation is regulated by facility agreements between Energinet.dk and Svenska Kraftnät.

The *power operation responsibility boundary* between Svenska Kraftnät and Energinet.dk lies at Läsö Öst, at the transition between the submarine and shore-end cables.

3.3 Switching responsible operator

During work between Lindome and XL1-F at Läsö Öst or Lindome and XL2-F at Läsö Öst, the Operations Centre at Råcksta (DCRÅ) shall be the *power operation manager* for the entire link up to Vester Hassing.

During work on the Danish parts of the link, Energinet.dk's control room at Vester Hassing is the *power operation manager* for the entire link up to Lindome.

3.4 Operation monitoring and control in respect of electrical safety

Operation monitoring and control is carried out from Energinet.dk's Operations Centre at Skærbæk or Vester Hassing and the Operation Centres at Råcksta (DCRÅ).

- Normally, bipolar operation is applied to Konti-Skan 1 and 2 but each of them can also be operated in monopolar mode.

3.5 Switching schedule

Switchings on the links are carried out in accordance with switching schedules drawn up by Svenska Kraftnät. Energinet.dk's Operations Centre at Skærbæk acknowledges receipt.

3.6 Disturbance management

3.6.1 Cross-border link trips – management

During *operational disturbances*, measures in accordance with issued instructions shall, as soon as possible, restore the link to *normal state*.

3.6.2 Switching schedule

In the event of faults requiring switchings impacting upon the *cross-border link,* Energinet.dk's Operations Centre at Skærbæk and Svenska Kraftnät are informed prior to any switchings being made. In the event of switchings on the Swedish grid, a switching schedule will be drawn up by Svenska Kraftnät.

3.6.3 Fault finding

Initial fault finding will be carried out differently from case to case. Generally speaking, the respective facility owner will be responsible for fault finding. For fault finding, a special preparedness plan for submarine cables has been drawn up.

3.6.4 Fault clearance, remaining faults

Once the fault has been localized, the respective facility owner will attend to clearing the fault. For fault clearance, a special preparedness plan for submarine cables has been drawn up.

4 System operation for facilities under 2

4.1 Transmission capacity (TTC)

The *transmission capacity* of the link is dependent on the temperature of the air and the earth.

In bipolar operation, the nominal capacity is 740 MW, and in monopolar operation (KS1 or KS2), the capacity is 370 MW.

Technical minimum capacity of KS1: 12 MW; KS2: 9 MW.

4.2 Routines for determining the transmission capacity

The *transmission capacity* between Jutland and Sweden shall be set on a routine basis by the *Parties*. In the case of intact connecting networks, the *transmission capacity* is determined by the thermal capacity of the facilities' components. The thermal overload capability allowed by monitoring equipment shall be capable of being used as and when required in accordance with special instructions. Technical data for the facilities' *transmission capacities* is reported in the current facility agreement between Energinet.dk and Svenska Kraftnät.

For any limitations in the connecting AC networks, Energinet.dk's Operations Centre at Skærbæk is responsible for supportive data on the Western Danish side and Svenska Kraftnät for the same on the Swedish side.

4.3 Trading capacity (NTC)

The normal *trading capacity* after the modernisation of the 400 kV line Nordjyllandsværket - Vester Hassing, scheduled to be commissioned in 2007, is:

740 MW from Western Denmark → Sweden
680 MW from Sweden → Western Denmark

Until then, the normal trading capacity is:

500 MW from Western Denmark → Sweden
620 MW from Sweden → Western Denmark

The above applies when Vester Hassing is the exchange point (30 MW of losses).

The following calendar day's *trading capacity* is set every day. Similarly, a weekly forecast is established for the coming week's *trading capacity*. The forecast is submitted to Nord Pool by at the latest the Tuesday of the week before. The *trading capacity* can be limited by line work, production in the connection area, overhauls etc.
Both *Parties* inform the other *Party* in good time prior to the relevant calendar day regarding the *transmission capacity* seen from the respective sides. The values that are the lowest will be the *trading capacity*.

4.4 Operation monitoring and control in respect of system operation

Operation monitoring and control is carried out from Energinet.dk's Operations Centre at Skærbæk and Svenska Kraftnät's Grid Supervisor at Network Control at Råcksta.

4.4.1 The power flow and distribution between the poles

Konti-Skan 1 and 2 are normally operated in bipolar mode.
During disturbances and maintenance on one pole, monopolar operation is applied.

4.4.2 Regulating the link

Regulation of the Konti-Skan links in accordance with agreed *exchange plans* will be carried out, until further notice, from the Danish side. Energinet.dk's Operations Centre at Skærbæk is responsible for its own *balance regulation* towards Sweden.

Regulation takes place, in principle, in accordance with a power plan using *ramping* transitions between different power levels. The plans are issued as power plans in whole MW for each 5 min of plan value. The links are regulated in accordance with this power linearly from power value to power value.

The power plan is determined in accordance with the energy and power plan agreements which form the basis for utilizing the Konti-Skan link.

4.5 Outage planning

The *Parties* shall, in consultation, plan outages on the link itself and on their own networks when these outages impact upon the *transmission capacity* of the link.

Operational planning and maintenance are co-ordinated between Svenska Kraftnät's Operational Department and Energinet.dk's Operations Centre at Skærbæk.

Overhaul planning is co-ordinated with the other HVDC links in the Nordic area.

4.6 System protection - emergency power

4.6.1 General

The Konti-Skan link is of major importance to Sweden and Denmark and outages due to disturbances thus generally entail major economic losses. In the event of *operational disturbances,* measures in accordance with issued instructions shall, as soon as possible, restore the link to *normal state*.

Automated operational disturbance systems are installed at Lindomen and Vester Hassing which can begin to function during *operational disturbances* on the Swedish or Jutland networks.

4.6.2 Emergency power

Emergency power is regulating measures which are initiated manually (*manual emergency power*) or automatically by means of a control signal being transmitted to the converter stations by means of telecommunications.

On the Western Danish side, Energinet.dk's Operations Centre at Skærbæk has the right to initiate *manual emergency power* in the event of disturbances to the power balance or *transmission network*.

On the Swedish side, Svenska Kraftnät has the right to initiate *manual emergency power* in the event of disturbances to the power balance or *transmission network*. Svenska Kraftnät can give Vattenfall Regionnät AB the right to initiate the *operational reserve* during disturbances on the regional network in western Sweden.

Manual emergency power of less than 100 MW and 100 MWh/calendar day may be activated without previous notification. Prior to activation over and above this, notification and approval shall occur between the control room staff of Energinet.dk's Operations Centre at Skærbæk and Svenska Kraftnät's Grid Supervisor at Network Control at Råcksta.

4.6.3 System protection

At the DC facilities, *system protection* is installed in the form of an *emergency power* function. Activation criteria for *emergency power* can be locally-measured frequency and voltage or via telecommunications on the basis of a supplied signal. In the event of activation, any ongoing normal regulation will be interrupted. Activation over and above the agreed limits and regulation back to plan may not occur until the counterparty has approved this. (See further in Appendix 5 – System protection).

5 Miscellaneous

5.1 System services

5.1.1 Transmission scope for operation reserves

Available *transmission capacity* can be used for the automatic or manual activation of *operational reserves*.

The *regulation margin* is maintained following the agreement between the *Parties* taking into account the exchange of *system services*. The *Parties* have the right to utilize idle *transmission capacity* for the transmission of *system services.* Configuration values, power limits etc. are agreed upon bilaterally.

JOINT OPERATION BETWEEN THE EASTERN DANISH AND SWEDISH SUBSYSTEMS ON THE AC LINKS ACROSS ÖRESUND AND TO BORNHOLM

1 Background

The *subsystems* of Norway, Sweden, Finland and Eastern Denmark are synchronously interconnected. The *subsystem* of Western Denmark is connected to Norway and Sweden using DC links. This Appendix describes the operation of the AC links across Öresund and to Bornholm.

2 Transmission facilities linking the subsystems of Eastern Denmark and Sweden

2.1 Transmission facilities owned/held by system operators at both ends

Facility	Voltage level	Settlement point
Hovegaard - Söderåsen (FL25)	400 kV	Söderåsen
Gørløse - Söderåsen (FL23)	400 kV	Gørløse

The ownership structure of the facilities is set out in ”Anlægsaftalen for 400 kV forbindelserna” between Svenska Kraftnät and Elkraft Transmission (merged with Energinet.dk as of 1 January 2005), dated 12 December 2001.

Svenska Kraftnät owns three single phase 400 kV cables included in FL23, cables K4001, K4002 and K4003, between Kristinelund and Ellekilde Hage, including the corresponding share belonging to the oil equipment at Kristinelund and Ellekilde Hage. The ownership boundary between wholly-owned Danish and Swedish facilities is constituted by the splicing points between the land lines and submarine cables on the Danish side. The cable joints belong to the Swedish-owned facilities.

A single phase 400 kV cable K4004 between Kristinelund and Ellekilde Hage, including the corresponding share belonging to oil equipment at Kristinelund and Ellekilde Hage, is owned to 50 % by Svenska Kraftnät and to 50 % by Energinet.dk. The boundary between K4004 and surrounding facilities is composed of the splicing points between the land lines and submarine cables on both the Danish and Swedish sides. The cable joints are part of K4004.

Energinet.dk owns three single phase 400 kV cables which are included in FL25, cables K4005, K4006 and K4007, between the Swedish shore and Ellekilde Hage, with associated oil equipment at Kristinelund and Skibstrupgaard. The ownership boundary between the Danish and Swedish-owned facilities is constituted by the splicing points between the submarine cables and land lines on the Swedish side. The cable joints belong to the Danish-owned facilities.

2.2 Other transmission facilities

Facility	Voltage level	Settlement point
Teglstrupgaard 1 - Mörarp	130 kV	Mörarp
Teglstrupgaard 2 - Mörarp	130 kV	Teglstrupgaard
Hasle, Bornholm - Borrby	60 kV	Borrby

The ownership structure of the 130 kV links is set out in ”Anlægsaftalen for 132 kV forbindelserna” between Sydkraft and Elkraft Transmission (merged with Energinet.dk as of 1 January 2005), dated 13 May 2002.

The ownership structure of the 60 kV facility is set out in ”Anlægsaftale for 60 kV forbindelsen” between Sydkraft and Østkraft.

3 Electrical safety for facilities under 2.1

3.1 General

The common ground for the electrical safety work of the *system operator* companies within Nordel is constituted by the European standard for managing electrical high-voltage facilities - EN 50 110 - which governs the organisation and working methods.
In addition to the standard, there are national regulations and special instructions which entail certain mutual differences between the *system operators* as regards dealing with operational issues from an electrical safety point of view.

3.2 Responsibility for electrical operation/Operational management

Responsibility for electrical operation of the 400 kV Öresund links on the Swedish side is held by Svenska Kraftnät, and operational management on the Danish side is carried out by Energinet.dk.

The *power operation responsibility boundaries* for electrical operation/operational management are the same as the ownership boundaries, see under 2.1.

The *power operation manager* of K4004 is Svenska Kraftnät.

3.3 Switching responsible operator/Switching leader

The *power operation manager* for the 400 kV Öresund links on the Swedish side is Svenska Kraftnät’s Operations Centre at Råcksta (DCRÅ), and the switching leader on the Danish side is Energinet.dk’s Control Centre at Ballerup.

Switchings on the links take place after agreement between Svenska Kraftnät's Operations Centre at Råcksta (DCRÅ) and Energinet.dk's Control Centre at Ballerup.

The *party* which initiates a planned outage is the switching responsible operator/switching leader for the switchings and other operational measures carried out (leading switching leader) if not otherwise agreed upon.

In the event of faults which require switchings that have an impact on the 400 kV Öresund links, that *party* whose facility suffers from the fault is the switching responsible operator/switching leader for the switchings and other operational measures carried out (leading switching leader).

If the fault cannot be located, the switchings shall take place on the basis of mutual consultation.

If a *party* needs switchings by the other *party* because of electrical safety reasons, the other *party* shall carry out such switchings without delay.

3.4 Operation monitoring and control in respect of electrical safety

Operation monitoring and control of the 400 kV Öresund links is managed on the Danish side by Energinet.dk's Control Centre at Ballerup and on the Swedish side by Svenska Kraftnät's Operations Centre at Råcksta (DCRÅ).

Both *parties'* switching responsible operators/switching leaders have access to status indications and electronic measured values via remote control from each others' facilities and from those stations where the 400 kV Öresund links are connected to the respective *parties'* grids.

3.5 Operational orders/Switching schedule

Switchings on the links are carried out in accordance with operational orders drawn up by Svenska Kraftnät's Outage Planning at Råcksta. Energinet.dk's Control Centre at Ballerup shall acknowledge the receipt of order.

The *parties* shall exchange switching confirmations in accordance with the operational orders/switching schedule before the work begins and after the work is complete.

3.6 Disturbance management

3.6.1 Cross-border link trips – management

In the event of *operational disturbances,* measures in accordance with issued instructions shall, as soon as possible, restore the link to *normal state*.

3.6.2 Switching schedule/Operational orders

In the event of faults requiring switchings which have an impact on the 400 kV Öresund links, Energinet.dk's Control Room at Ballerup and Svenska Kraftnät's Operations Centre at Råcksta (DCRÅ) are informed prior to any switchings are made.
For switchings in the Swedish grid, a switching schedule/operational order is drawn up by Svenska Kraftnät's Operations Centre at Råcksta (DCRÅ).

For switchings in the Danish grid, a switching programme is drawn up by Energinet.dk's Control Room at Ballerup.

3.6.3 Fault finding

Initial fault finding is carried out differently from case to case. Generally, it is the respective facility owner who is responsible for fault finding. A special preparedness plan has been drawn up for fault finding and repair for submarine cables.

3.6.4 Fault clearance, remaining faults

Once the fault has been localized, the respective facility owner will look after fault clearance. For fault clearance, a special preparedness plan for submarine cables has been drawn up.

4 System operation for facilities under 2.1 and 2.2

4.1 Transmission capacity (TTC)

4.1.1 Transmission capacity in MW per cable bundle

Line	5 °C	15-20 °C	30 °C
Hovegaard – Söderåsen	830	830	830
Gørløse – Söderåsen	830	830	830
Teglstrupgaard 1 – Mörarp	182	182	154
Teglstrupgaard 2 – Mörarp	173	173	157
Hasle, Bornholm - Borrby,	51	51	51

4.1.2 Transmission capacity in MW per link

– To Eastern Denmark

Link	Capacity
Öresund (Zealand)	1,350
Bornholm	51

– To Sweden (thermal limitation)

Link	Capacity
Öresund (Zealand)	1,750
Bornholm	51

The *transmission capacities* of the links are technically dependent and can be affected by the current operational situation in Zealand.

4.2 Routines for determining the transmission capacity

The *transmission capacity* between Eastern Denmark and Sweden shall be set on a daily basis by the *Parties*.

4.3 Trading capacity (NTC)

Determination of the capacity is based on the combined *transmission capacity* of the 400, 130, and 60 kV *transmission facilities*. When determining the *trading capacity* of the links, the applicable *regulation margin* of 50 MW is taken into account. A weekly forecast for the *trading capacity* shall be established for the coming week.

If a country can guarantee *counter trading* and the existence of sufficient *fast active disturbance reserve,* the *trading capacity* may be increased.

4.4 Operation monitoring and control in respect of system operation

Operation monitoring of borders and transmission cross-sections, which can affect exchanges, is managed on the Danish side by Energinet.dk's Control Centre at Ballerup and on the Swedish side by Svenska Kraftnät's Network Control Centre at Råcksta (SvK-vhi).

4.5 Voltage regulation

The basic principle for voltage regulation is governed by item 7 point 7.5 in the agreement.

4.5.1 Voltage regulation on the Swedish side

The Operations Centre in Råcksta (DCRÅ) is responsible for voltage regulation in the southern parts of the grid.
The following voltage levels are applied:

Substation	Min voltage kV	Normal operation range kV	Max voltage kV
Söderåsen	395	400-410	420

4.5.2 Voltage regulation on the Danish side

The Control Centre at Ballerup is responsible for voltage control in Zealand.
The following voltage levels are applied:

Substation	Min voltage kV	Normal operation range kV	Max voltage kV
Hovegaard	380	390-410	420
Gørløse	380	390-410	420
Teglstrupgaard 1	130	130-137	137
Teglstrupgaard 2	130	130-137	137

4.5.3 Co-ordination of voltage regulation

Mvar contribution from the cables is distributed between Svenska Kraftnät and Energinet.dk in the same proportion as their ownership.
At a voltage of 400 kV, the facilities FL23 and FL 25 each will generate 150 – 170 Mvar. The reactors at Hovegaard and Söderåsen compensate this generation by 110 Mvar per line.
The 400 kV voltage at Hovegaard and Söderåsen shall be regulated so that the given Mvar distribution is achieved as well as possible. Minor deviations in the region of 25 Mvar are accepted in normal operation. Short-term deviations from this Mvar range can occur for example in conjunction with the connection of capacitor batteries or reactors. There can be deviations in the Mvar distribution in conjunction with disturbances.

4.6 Outage planning

The *Parties* shall, in consultation, plan outages on the links and on their own networks if the *transmission capacity* of the links is affected.

Operational planning and maintenance are co-ordinated in consultation between Energinet.dk's Operational Planning at Ballerup and Svenska Kraftnät's Outage Planning at Råcksta.

Operational planning and maintenance which affects the entire Nordic system shall, whenever possible, be co-ordinated in consultation with all *system operators*.

4.7 Disturbance management

The term disturbance situation means that the *transmission capacity* has been exceeded due to, for instance, long-term line faults or losses of production. If the *transmission capacities* are not exceeded during the faults, the situation will be deemed normal.

In the event of *operational disturbances*, measures in accordance with issued instructions shall, as soon as possible, restore the link to *normal state*.

5 Miscellaneous

5.1 Parallel operation 130 kV

Power transmitted via the 130 kV network does not entail any liability to render payment or any other reimbursement of expenses from Svenska Kraftnät or Energinet.dk.

5.2 Transmissions to Bornholm

As regards balance, Bornholm is managed as a part of the Eastern Danish *subsystem*. Energinet.dk shall be responsible for the production resources on Bornholm being capable of being utilized for general system operation requirements in the same way as the production resources in the rest of Eastern Denmark.

5.3 Co-ordination of fast active disturbance reserve south of cross-section 4

Svenska Kraftnät and Energinet.dk shall ensure that there is sufficient *fast active disturbance reserve* to cope with *dimensioning faults* based upon each *subsystem's* responsibility for its own reserves. Svenska Kraftnät and Energinet.dk's Control Centre at Ballerup shall exchange information regarding how much *fast active disturbance reserve* there is which can restore the operational situation to *normal state* following a fault.

During *normal state,* Svenska Kraftnät and Energinet.dk's Control Centre at Ballerup co-ordinate the *fast active disturbance reserve* in Southern Sweden and Eastern Denmark in accordance with the following distribution rules:

(Dimensioning fault) x (own fault) / (own fault + counterparty fault)

Dimensioning fault = largest fault in area south of cross-section 4

Own fault = largest fault in own area south of cross-section 4

Counterparty fault = largest fault in counterparty's area south of cross-section 4

In Sweden, south of cross-section 4, the largest fault is typically the result of:
- Network part of cross-section 4
- Baltic Cable
- SwePol Link.

In Eastern Denmark, the largest fault is typically the result of:
- Unit at the Avedøre or Asnæs plants
- KONTEK.

5.4 Counter trading

Energinet.dk’s Control Centre at Ballerup can agree with Svenska Kraftnät on *counter trade* in Sweden to increase the *trading capacity* between Sweden and Eastern Denmark. Energinet.dk shall in this context compensate all of Svenska Kraftnät’s costs in respect of this *counter trading*.

JOINT TRIANGULAR OPERATION BETWEEN THE NORWEGIAN, SWEDISH AND WESTERN DANISH SUBSYSTEMS

1 Transmission facilities triangularly linking the subsystems Sweden - Western Denmark - Norway

Facility	Voltage kV	Other
Hasle-Borgvik	400 kV AC	Included in Hasle cross-section
Halden-Skogssäter	400 kV AC	Included in Hasle cross-section
Stenkullen-V Hassing	250 kV DC	Konti-Skan 1
Lindome-V Hassing	285 kV DC	Konti-Skan 2
Kristiansand-Tjele 1 and 2	250 kV DC	Skagerrak 1 and 2
Kristiansand-Tjele 3	350 kV DC	Skagerrak 3

2 Principles for the distribution of exchange plans on the links

Nord Pool utilizes the *trading capacity* which the *system operators* have set in order to try to avoid price differences between the *Elspot areas*.

Energinet.dk's Control Centre at Skærbæk sets a *trading capacity* to and from the *Elspot area* in Western Denmark which can entail a limitation of the *trading capacity* between the *Elspot areas* Western Denmark - Norway and Western Denmark - Sweden. Distribution between the cables takes place on a pro rata basis, depending on the DC links' *trading capacities*. In the event of a price difference between the areas, the *trading capacity* will be redistributed so that it is increased from a low-*price area* to a high-*price area* within the framework of the overall *trading capacity*.

Svenska Kraftnät, Energinet.dk and Statnett agree that *trading plans* between Western Denmark and the rest of the Nordic *subsystem* will not be changed more than 600 MW from one hour to the next (this applies to the overall net regulation between Western Denmark and Sweden/Norway as well as per single link).

The planned *ramping* rate on Konti-Skan and the Skagerrak link is a maximum of 30 MW/min.

Based on hourly plans from Nord Pool Spot, Energinet.dk's Control Centre at Skærbæk draws up preliminary power plans on the DC links towards Sweden and Norway with *ramping* transitions between the different power levels, taking into account the *ramping* rate and minimising network losses in the triangular link. Energinet.dk's Control Centre at Skærbæk is responsible for the plans meeting the stipulated requirements.

The *UCTE* system has a requirement that the entire regulation must be completed within +/- 5 minutes at hour shifts.

Transits through Western Denmark entail that power plans and regulations for the DC links reflect the *UCTE* requirement.

These power plans can later be re-planned as a result of exchanges of *supportive power*, either bilaterally between two of the relevant *system operators* or between all three *system operators*.

The exchange of equal volumes of *supportive power* between all three *system operators* in a triangle (triangular trading) is used to relieve heavily loaded links on the network, to obtain scope for regulating the frequency and to minimise the need for *counter trading*. All three *system operators* can take the initiative as regards *supportive power* trading via the relevant DC links or the Hasle cross-section. Statnett has a co-ordinating function. Triangular trading requires the approval of all three *Parties*.

Energinet.dk's Control Centre at Skærbæk is responsible for drawing up new power plans for the DC links in accordance with the stipulated requirements and for informing the other *system operators*.

All *Parties* shall be informed about the potential *transmission capacity* of all three links as regards the allocation of *balance power* and *supportive power*.

MANAGING TRANSMISSION LIMITATIONS BETWEEN SUBSYSTEMS

1 Background

All *trading capacity (NTC)* shall be put at the disposal of the electricity market.

System operators may need, for reasons of *system security* or the state of affairs in their own or adjacent networks, to limit the *transmission capacity* of the links between the *subsystems*.

For the *transmission capacity* of the *cross-border links* between *Elspot areas*, the same prioritization rules are to be applied by all *system operators* in the *subsystems*. See table below.

Priority		Sweden	Finland	Norway	Eastern Denmark	Western Denmark
1	Elspot	X	X	X	X	X
2	Elbas	X	X		X	
3	Balance power/ Supportive power	X	X	X	X	X

Supportive power agreed in advance between the *system operators,* with reference to start-ups of thermal power or similar, has a higher priority than *balance power*.

2 Transmission limitations during the planning phase, prior to completed trading on Elspot

2.1 Elspot is used to balance transmission limitations between the *subsystems* during the *planning phase*. The involved *Parties* reach agreement on a daily basis regarding the *trading capacity* for exchanges between the *subsystems*.

2.2 In the event of limited-duration reduced *transmission capacity* between the *subsystems*, the *system operators* will be able to agree to use *counter trading*.

2.3 In the event of transmission limitations within an *Elspot area,* it will be the respective *system operator's* responsibility to manage the limitation by using *counter trading* or by limiting the *trading capacity*.

3 Transmission limitations during the operational phase, following completed trading on Elspot

3.1 During the *operational phase*, reduced *transmission capacity* between the *subsystems*, as a consequence of an *operational disturbance*, is managed by means of *counter trading*. There is no limitation of the *players'* planned power trading on Elspot. *Counter trading* takes place during the remainder of the current period when trade on Elspot has been fixed.

For *Elbas trading*, the *trading capacity* is reduced but prearranged trading will be *counter traded* for the remainder of the current Elspot period.

3.2 In the event of an *operational disturbance* in a *Party's subsystem*, the responsible *Party* will bear the full technical, financial and operative liability for eliminating the effects of the incident in its own *subsystem* and minimising the effects in other *sybsystems*.

3.3 In the event of an *operational disturbance* on the *cross-border links* themselves, the *system operators* on both sides of the link will bear the technical, financial and operative liability for eliminating the effects of the incident on their own *subsystems*.

If the agreed trading exceeds the reduced *trading capacity* between *subsystems*, *supportive power* is exchanged between the parties concerned. The volume of *supportive power* in *counter trading* as a result of an *operational disturbance* on the *cross-border link* itself is normally the difference between the agreed trading capacity and current *trading capacity*.

3.4 Acute situations, such as during a general *power shortage* or during *power shortages* resulting from *operational disturbances* in networks or during *bottleneck situations*, when compulsory *load shedding* has to occur, are managed in accordance with Appendix 9.

4 Step by step of the trading capacity

During major changes to the *transmission capacity* between two *Elspot areas,* this can entail major changes in power flows from one hour to the next. These major changes can be difficult to manage regulation-wise. Thus, restrictions are placed on changes to *trading capacities*, MWh/h, from one hour to the next. This change may be a maximum of 600 MWh/h, unless otherwise agreed.

RULES FOR MANAGING POWER SHORTAGES DURING HIGH CONSUMPTION, BOTTLENECKS OR DISTURBANCES

Introduction

These rules describe how the *system operators* of the *interconnected Nordic power system* shall jointly manage possible *power shortages.* This shall be carried out with a level of *system security* which is as high as possible.

Extracts from Appendix 1 Definitions:

A **subsystem** is the power system for which a *system operator* is responsible. A *system operator* can be responsible for several *subsystems*.

Subsystem balance is calculated as the sum of measured physical transmissions on the *cross-border links* between the *subsystems*. Thus, there is a deficit if this sum shows that power is flowing into a *subsystem* and a surplus if power is flowing out of a *subsystem*. (Exchanges on *cross-border links* like Finland-Russia, Norway-Russia, the SwePol Link, Baltic Cable, Kontek and Western Denmark-Germany are not to be included in the calculation.)

A risk of power shortage defines the state when forecasts show that a *subsystem* is no longer capable of maintaining the demand for a *manual active reserve,* which can be activated within 15 minutes, for the planning period.

Power shortage occurs during the hour of operation when a *subsystem* is no longer capable of maintaining the demand for a *manual active reserve* which can be activated within 15 minutes.

Critical power shortage occurs during the hour of operation when consumption has to be reduced/disconnected without commercial agreements about this.

Prerequisites

- Each *subsystem* is responsible for its own balance and for the requirements for automatic and manual reserves being fulfilled.

- All regulation resources shall exist as *regulation bids* on the joint Nordic *regulation list*. This concerns both market-based bids and *manual active reserve* (15 min).

- *System operators* inform each other on a continuous basis.

- A *subsystem* with a physical surplus does not need to carry out *load shedding* to the benefit of *subsystems* with a deficit.

- The need for *manual active reserve* (15 min) in each *subsystem* shall normally be equal to or greater than the *dimensioning faults* in each *subsystem.*

- When *power shortages* or *critical power shortages* exist, the *manual active reserve* (15 min) is reduced to less than the normal level.
  The *manual active reserve* (15 min), however, must not fall short of 600 MW, in total, in the *synchronous system.*

- The physical *transmission capacities* of the network shall be maintained and a frequency which does not drop below 50.0 Hz shall be aimed at.

- Each *system operator* formulates instructions which comply with this set of rules. The content of the instructions is co-ordinated between the *system operators*.

1 General power shortages without bottlenecks in the network

1.1 Maintenance of manual active reserve (15 min)

- When a *subsystem* in normal *balance regulation* is approaching the limit of keeping the *manual active reserve* (15 min) in its own *subsystem* for its *dimensioning faults*, the control centres of the other *system operators* shall be informed. This shall also be done even if there is a surplus in the *subsystem*. This information shall be delivered by e-mail and by telephone as early as possible.

- The *system operators* concerned assess whether the *manual active reserve* (15 min) in their own *subsystem* can also be used for upward regulation purposes in normal balance regulation. This means that the *subsystem* will not have sufficient own reserves to cover the need for *manual active reserve* (15 min).

- If further *upward regulation* is needed, the parties shall ascertain whether there are available market-based upward regulation bids in the neighbouring systems to cover the *subsystem*'s deficit of *manual active reserve* (15 min). “Available” means that resources can be activated for this purpose and that there is sufficient *transmission capacity*.

- If there are available market-based upward regulation bids, the parties can agree on maintaining part of the need for *manual active reserve* (15 min) in another *subsystem*. In this case, upward regulation can take place in price order in the joint Nordic *regulation list*.

- In further upward regulation in price order, the *subsystem* can maintain parts of its *manual active reserve* (15 min) continuously. The *system operator* of the *subsystem* shall specify the volume and composition of this reserve on the basis of the current operational situation.

- If there are not available market-based upward regulation bids in the neighbouring systems to cover the *subsystem*'s deficit of *manual active reserve* (15 min), a *power shortage* generally takes place in accordance with item 1.3.

1.2 Risk of power shortages

- The *system operator* shall inform the other *Parties* as quickly as possible. The measures in question will be taken in order to avoid an unacceptable reduction of the *system security*.

- Whenever required, the market *players* shall be informed via UMM as soon as possible. The information shall also be delivered directly from the *system operators* to the other P*arties*.

- At least 600 MW of the most expensive *manual active reserve* (15 min) *in the regulation list* will be earmarked for each hour. Unavailable *regulation bids* will be marked on the joint *regulation list*. When there is a potential risk of *bottlenecks* arising, the reserve is to be distributed in consultation between the *Parties*.

- The starting of *slow active disturbance reserve* and *peak load reserve* will be assessed. The other *system operators* will be informed on plans to start the reserve. The costs of starting the reserve in order to keep it in readiness are considered as *special regulation*.

1.3 Power shortages

- When a *subsystem* is no longer capable of meeting the requirement for *manual active reserve* (15 min) and there are not sufficient available market-based *regulation bids* in the neighbouring systems, the other *system operators* are to be informed as quickly as possible

- Prearranged trading between *players* is fixed and cannot be changed.

- Svenska Kraftnät and/or Fingrid can demand that cross-border trading on Elbas between Sweden and Finland ceases, and Svenska Kraftnät and/or Energinet.dk can demand that cross-border trading on Elbas between Sweden and Eastern Denmark ceases.

- When there is a requirement for upward regulation, bids on the *regulation list* are to be used in the order of price unless the *regulating power* will lead to *bottlenecks* in the *transmission network* or will be unavailable for other reasons. Market-based bids are used before *fast active disturbance reserve.* The earmarked *manual active reserve* will not, however, be activated until all of the remaining *regulation list* has been activated. When unexpected *bottlenecks* arise, the earmarked reserve can be redistributed.

1.4 Critical power shortages

- When a *critical power shortage* is approaching, preparations for manual *load shedding* (15 min) will be ordered in the *deficit areas*. The *Parties* will agree on the *subsystem(s)* where the *load shedding* will take place and where in the *subsystem(s)* the *load shedding* will take place. The consequences for load shift must be assessed.

- If no network problems arise, bids in the *regulation list* will be used until only 600 MW of *manual active reserve* (15 min) remains in the *synchronous system*. The activation of *regulation bids* shall take place in price order, and if frequency regulation so requires, all market-based bids shall be activated before the *fast disturbance reserve*.

- When only 600 MW of *manual active reserve* (15 min) remains in the *synchronous system*, it will be activated and retained as increased *frequency controlled normal operation reserve*. The activated reserve of at least 600 MW will be redistributed among rapidly regulating hydropower production in consultation between the *Parties.* The most expensive available upward regulation bid in hydropower production shall be deactivated. Bids with a low volume can be skipped in order to facilitate their handling. If there are no upward regulation bids, the downward regulations will be activated in price order. SvK and Statnett are responsible for and co-ordinate this.

- At the same time, *load shedding* will be ordered without a commercial agreement. The expected activation time for *load shedding* has to be weighed into the decision. *Load shedding* occurs in the *subsystem* with the greatest physical deficit in its balance. Shedding occurs in stages until the requirement for 600 MW of *manual active reserve* (15 min) in the *synchronous system* is met. When *load shedding* has taken place until two or more *subsystems* have an equally large deficit, *load shedding* is distributed thereafter between these *subsystems*. Attention must be paid to the practical handling; *load shedding* in stages of 200 – 300 MW at a time is considered a suitable level.

- When assessing a *subsystem's* balance, the *manual active reserve* (15 min) that is not activated must be taken into account. A *subsystem* with a physical deficit which can regulate itself into balance does not need to implement *load shedding.*

- The *system operator* that carries out *load shedding* shall inform the market and the other *system operators* of *critical power shortage*.

2 Regional power shortages caused by bottlenecks or network disturbances

- The relevant *subsystem* is responsible for measures as long as regulation resources are available.

- If time allows, preparations for *manual load shedding* (15 min) will be ordered in the *deficit areas*.

- If a *bottleneck* arises within a *subsystem* towards a area with a deficit and all available bids in the merit order *regulation list* that are without sufficient *manual active reserve* (15 min) within the area are activated, then *load shedding* will be ordered outside the merit order *regulation list*. *Load shedding* will be carried out in the *subsystem* with the greatest physical deficit in its balance and which remedies the *bottleneck.*

- When assessing a *subsystem's* balance, the *manual active reserve* (15 min) which is not activated must be taken into account. A *subsystem* with a physical deficit which can regulate itself into balance does not need to implement *load shedding.*

- If there are stable consumption conditions, the need for *manual active reserve* (15 min) within the *deficit area* will be less than if consumption had been rising. However, *manual active reserve* (15 min) must not fall short of 600 MW in the *synchronous system*.

3 Connection of consumption following load shedding

- When the power balance within the *deficit area* improves, consumption will be reconnected in small steps. The potential for increased consumption as a consequence of shedding must be taken into account.

4 Pricing

The pricing of *supportive power* and *balance power* shall be set in accordance with normal principles. Normally, no *supportive power* shall be agreed upon, instead the power will be exchanged as *balance power*. In the event of price disputes, the setting of prices shall take place afterwards. The correction of irregularities in the pricing can be achieved by means of subsequently reaching agreement about *supportive power*.

THE INTERCONNECTED NORDIC POWER SYSTEM'S JOINT OPERATION WITH OTHER SYSTEMS

1 Western Denmark's joint operation with the UCTE system

1.1 Western Denmark's joint operation with 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*. Effective 25 October 2001, Energinet.dk is formally an associated member of *UCTE*.

Energinet.dk's relationship with E.ON Netz is such that it does not have a formal system operation agreement with E.ON Netz, but there is a draft which is being processed.

In Germany, there is a "Grid Code" for the collaboration conditions relating to the technical system operation between the German *system operators*.

1.1.1 System operation collaboration with E.ON Netz

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 Appendix 2 section 5

- 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 *load shedding* is co-ordinated.

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.

1.1.2 Commercial conditions

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.

1.2 Western Denmark’s joint operation with Flensborg

Since the beginning of the 1920’s, Stadtwerke Flensborg (SWF) has conducted AC collaboration across the Danish-German border. This collaboration has, with time, become more and more intensive, and a 150 kV link between Flensborg and Ensted is now established.

Energinet.dk and SWF have entered into an agreement which regulates the system operation and market conditions.

1.2.1 System operation collaboration with SWG

Stadtwerke Flensborg is connected to Energinet.dk via the following links:
- 150 kV Ensted – Flensborg, settlement point Ensted
- 60 kV links between Kruså and Flensborg.

The *transmission capacity* is normally 150 MW in both directions.

SWF has the opportunity to carry out exchanges with Slesvig via the 60kV network. Exchanges are regulated via a transverse voltage transformer.

1.2.2 Commercial conditions

SWF has a limited-duration prioritized transmission for utilizing the capacity of the network between Energinet.dk and SWF, i.e. on the 150 kV link between Flensborg and the Ensted station.

In SWF's area, there are no other market players than SWF as a producer. When other players emerge, and there are capacity limitations, an auction system will be introduced which will correspond to that which applies between Energinet.dk and E.ON Netz today.

2 The synchronous system's joint operation with the UCTE system

2.1 The synchronous system's joint operation with Germany via the Baltic Cable

The Baltic Cable is an HVDC link between Sweden and Germany. The link goes between Trelleborg on the Swedish side and Lübeck on the German side. Baltic Cable AB owns the cable link. Co-owners are E.ON Sverige and Statkraft Europa.

The capacity is 600 MW.

2.1.1 System operation collaboration with E.ON Netz

There is no system operation agreement. The *system services* that exist have been produced vis-à-vis E.ON Sverige. The link is equipped with an *emergency power* function. There is also a *system protection* function, which provides a greater *transmission capacity* in southern Sweden.

2.1.2 Commercial conditions

The link is used today for *Elspot trading*. The utilization fees are regulated by means of a tariff. Idle capacity permitting, there are opportunities for Svenska Kraftnät to do *supportive power* deals via E.ON Sverige.

2.2 The synchronous system's joint operation with Germany via Kontek

Kontek is an HVDC link between Eastern Denmark and Germany.
The link 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.

2.2.1 System operation collaboration with Vattenfall Europe Transmission

The combined suite of agreements (entered into between the former VEAG and the former ELKRAFT) contains rules for system operation as well as allocation. As yet, there is no separate system operation agreement.
There is an agreement regarding a *system protection* function, which could yield a higher transmission capability in southern Sweden.

2.2.2 Commercial conditions

The link's *transmission capacity* is utilized as follows:

Southbound:
550 MW is made available to Nord Pool Spot for *Elspot trading* until the middle of 2006.
50 MW is utilized for the *frequency controlled disturbance reserve*.

Northbound:
550 MW is made available to Nord Pool Spot for *Elspot trading* until the middle of 2006.
50 MW is utilized for the *frequency controlled disturbance reserve*.

Settlement point: Bentwisch.

2.3 The synchronous system's joint operation with Poland

SwePol Link is an HVDC link between Sweden and Poland. The link goes between Karlshamn on the Swedish side and Slupsk on the Polish side. SwePol Link AB owns the cable link. The owners are:

Svenska Kraftnät
Vattenfall AB
Polish Power Grid Company (PPGC)

The capacity is 600 MW.
The *system operator* on the Polish side is Polskie Sieci Elektroenergetyczne (PSE).

2.3.1 System operation collaboration with PSE

The system operation collaboration is regulated by a system operation agreement. This agreement regulates, for instance:

- Technical limitations
- Outage co-ordination
- *Emergency power functions*
- Exchanges of *trading plans*.

The link is regulated half-yearly from the respective *system operator*.

2.3.2 Commercial conditions

SwePol Link AB is a transmission company that sells *transmission capacity* on the link.
The utilization fees are regulated by means of a tariff. 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 permitting, there are opportunities for the respective *system operator* to do *supportive power* deals.

3 The synchronous system's joint operation with Russia

Electricity imports from Russia began in 1960. There was a significant increase in imports at the beginning of the 1980's, when the HVDC stations at Viborg and the double 400 kV lines were commissioned. The third 400 kV line went into commercial operation at the beginning of 2003.

3.1 System operation collaboration with RAO UES of Russia

The Finnish grid is connected with Russia via three 400 kV lines from Viborg (Russia) to Yllikkälä and Kymi (both Finland). The technical *transmission capacity* is 1,400 MW. Transmissions take place via the HVDC stations at Viborg and from a 450 MW gas-fired power plant which is in isolated operation, i.e. synchronised with the *synchronous system*. In addition to this, there are two 110 kV links owned by private regional network companies.

Fingrid and RAO UES of Russia signed a system operation agreement on 6 February 2003, which regulates operational and technical relations between the power systems. Nordel's recommendations and requirements have been taken into account.

3.2 Commercial conditions

For technical and commercial reasons, trading via the link only occurs from Russia to Finland. The *trading capacity* is 1,300 MW.

The transmission service is based upon a firm fixed-period transmission. The minimum period for a transmission reservation is one year while the longest is three years. The smallest volume for individual *players* is 50 MW.

The daily hourly transmission programme is agreed upon on a daily basis and imports are managed as a firm delivery in the balance settlement. Fingrid carries the balance responsibility for the delivery.

Fingrid and RAO UES of Russia have agreed that the link and the HVDC stations at Viborg may also be used for technical requirements. 100 MW has been reserved for this purpose. The link is used for frequency regulation and can also be used for *fast active disturbance reserve*.

The following documents have been included in this chapter:

Document	*Status*
Nordel's connection requirements to be met by thermal production plants (Operational performance specifications for thermal power units larger than 100 MW and Operational performance specifications for thermal power units smaller than 100 MW), 1995	*Recommendations*
Dimensioning practice in the Nordic countries, Nordel's system committee, 1998	*Descriptive*
Nordel Connection Code Wind Turbines, November 2006, Edited by the ad-hoc group Jan Havsager Energinet.dk, Inge Vognild Statnett, Matti Lahtinen Fingrid, Erik Thunberg Svenska Kraftnät and Fredrik Norlund Svenska Kraftnät	*Recommendations*

The following national documents deal with the Connection Code:

Document	*Status*
Electrical quality: The working group has attempted to bring together the regulations of the different countries. Not complete.	*Varying: Guidelines (Sweden, Finland, Norway)*
Production: The working group has attempted to upgrade Nordel's recommendation for thermal power plants to apply to all types of power plant, on the basis of national regulations:	
Sweden: Technical design of power plants regarding reliability (SvKFS 2005:2 Affärsverket svenska kraftnäts föreskrifter och almänna råd om driftsäkerhetsteknisk utformning av produktionsanläggningar)	*Binding regulation (according to delegation in law)*
Norway: Regulations for hydro power	*Guidelines*
Finland: General Connection Terms of Fingrid Oyj's Grid, Specifications for the Operational Performance of Power Plants, Power Quality in Fingrid's 110 kV grid	*Binding requirements and recommendations*
Denmark: *Technical Regulations of Thermal Power Station Units of 1,5 MW or above (July 2006)* *Technical Regulations of Thermal Power Station Units below 1,5 MW (work in progress)* *Requirements to be met by wind power installations connected above 100 kV (December 2004)* *Rules for regulation units (work in progress)*	*Binding requirements*
Upgrading not complete.	

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CONNECTION CODE

1 Introduction

The purpose is to lay down certain basic rules for connection to the transmission system on non-discriminating terms. There are national requirements which shall be taken into account in the first place.

The connection conditions specify requirements for minimum technical requirements to ensure security of operation in the Nordic electric power system. The connection conditions lay down the lowest technical requirements that a plant must satisfy to have access to the grid, and the lowest technical requirements to be met by a plant that may be important to the operational reliability of the Nordic electric power system. The respective TSOs lay down national requirements. They should be based on minimum requirements laid down in this Connection Code, but may be stricter.

The Connection Code applies to new installations or to the reconstruction of existing installations. Existing installations must retain the properties they had when they were connected to the grid.

2 Connection to the grid

2.1 Electrical quality (in systems of 110 kV and above)

This section has been written with national requirements in mind.

2.1.1 Frequency

The nominal frequency is 50 Hz. Under normal operating conditions (synchronous operation of the Nordic grid) the frequency will typically remain within the range 49.9 to 50.1 Hz. However, larger frequency deviations may occur during operational disturbances. See Section 4.1.2 of the System Operation Agreement, appendix 2.

2.1.2 Voltages and slow voltage variations

The nominal voltages between the phases (UN) and the corresponding minimum insulation levels for the equipment (the insulation levels are normally lower for power lines) are shown in the table below:

Nominal voltage or rated voltage	Used for transmission in	Highest operating voltage on equipment	Withstand voltage for lightning surge (LIWL)	Withstand voltage for switching surge (SIWL)	50 Hz, 1 min withstand voltage
110	Finland	123	550	-	230
132	Denmark, Norway	145 [1)]	650	-	275
150	Denmark	170	750	-	325
220	Denmark, Finland, Sweden	245	950	-	395
300	Norway	300	1050	850	-
400	Denmark, Finland, Norway, Sweden	420	1425 1350 (DEN West)	1050	-

[1)] Isolation level. Highest operating voltage is 138 kV according to thermal dimensioning of transformer core, 105% of rated voltage due to induction.

The lowest operating voltages at each voltage level are highly dependent on the local conditions. The lowest values are reached during operational disturbances and are usually not lower than 90 % of the nominal voltage.

2.1.3 Rapid voltage variations

During normal operating conditions, a rapid voltage variation does not typically exceed 5 % of the nominal voltage.

A rapid voltage variation due to a single regulation or switching action must not generally exceed 3 % of the nominal voltage. However, the value must be lower if the action is constantly repeated, e.g. several times a day (the exact requirement depends on the local conditions).

Comment: A rapid voltage variation that causes a voltage, which falls below 90 % of the pre-existing voltage, is regarded as a voltage dip.

Rapid periodic voltage variations are known as flicker and the severity of these must be measured with special instruments. The aim is to keep the measured value for short-term flicker (Pst) below 1.0 and the measured value for long-term flicker (Plt) below 0.8. The limit values apply to 95 % of all measured values during a period of one week. Permitted flicker due to only one connecting party is usually lower than these values but is highly dependent on local conditions.

2.1.4 Voltage dips

A voltage reduction with duration of 10 ms to 1 minute and a voltage drop of more than 10 % of the existing value is known as a voltage dip. There are no standard requirements for the severity or extent of voltage dips since they are highly dependent on the grid structure, weather conditions, etc. Most voltage dips are caused by earthing faults. Whether or not such voltage dips are transferred to lower voltages depends on which earthing methods are used and on the transformer connections. The voltage dips may often become deeper and may also spread to larger parts of the grid if faults occur in more than one phase, but this is relatively rare. The duration of a voltage dip is highly dependent on the type of fault concerned and on which relay protection methods are used locally.

2.1.5 Outages

At outages, the voltage at the customer's connection point is below 1 % of the nominal voltage. Outages can be divided into planned outages (customers are informed beforehand) and outages due to operational disturbances. The negative effects of outages differ greatly between the two cases. There are no standards with defined limit values for outages.

2.1.6 Overvoltages

Temporary overvoltages

Earth faults are the most common cause of temporary overvoltages. During the fault, the voltage in normal phases rises. The voltage may rise up to 1.8 times the rated voltage, depending on the earthing method used in the grid. In practice, however, the voltage is usually kept to a lower level.

Switching and lightning overvoltages
Switching-in of shunt capacitors and auto-reclosure of lines are the most common causes of switching overvoltages. During switching of a capacitor, the voltages between phase and earth may, depending on the earthing method used, reach values up to 1.8 times the peak value of the phase voltage (1.8 p.u.). Switching of lines, especially rapid automatic reclosure of lines, may cause high over voltages, up to 3 p.u. However, the probability of such high values is low. Overvoltages on the overhead lines of the grid due to atmospheric phenomena are largely limited by the dielectric strength of the lines and the overvoltage protection of the transformer stations. Because of these factors, it may largely be assumed that the over voltages will be limited to a level of 5-6 p.u.

2.1.7 Voltage imbalance

Depending on local conditions, the average measured values for 10 minutes for the phase component of a three-phase system with negative sequence must be below 1-2 % of the phase component with positive sequence for 95 % of the time over a measuring period of one week. In Sweden and Norway a limit value of 1 % is used. 2 % is used on the Finnish 110 kV grid.

2.1.8 Voltage harmonics

The figures in Table 1 must not be exceeded for voltages with harmonics. This means that 99 % of the average values for a period of 10 minutes over a measuring period of one week must be below the limit values. NOTE: The limit values differ between the countries.

PLANNING LEVELS FOR HARMONIC VOLTAGES As a percentage of the nominal voltage											
Odd				Odd				Even			
Multiples other than 3				Multiples of 3							
n	F	N	S	n	F	N	S	n	F	N	S
	%	%	%		%	%	%		%	%	%
5	3.0	2.0	2.5	3	3.0	2.0	2.0	2	1.0	1.5	1.0
7	2.5	2.0	2.5	9	1.5	1.0	1.0	4	0.7	1.0	1.0
11	1.7	1.5	1.5	15	0.5	0.3	0.6	6	0.5	0.5	0.5
13	1.7	1.5	1.5	21	0.5	0.2	0.4	8	0.3	0.2	0.5
17	1.5	1.0	1.0	>21	0.3	0.2	0.4	10		0.2	0.4
19	1.5	1.0	1.0					12		0.2	0.4
23	0.8	0.7	0.7					>12		0.2	0.2
25	0.8	0.7	0.7								
>25	0.5	0.2+ 0.5* 25/n	0.2+ 0.5* 25/n								
Total harmonic distortion (THD) for the voltage < 3% (F and N), < 4% (S)											

Table 1 (F = Finland, N = Norway, S = Sweden)

2.1.9 Voltages with intermediate harmonics

Voltages that contain intermediate harmonics are usually far lower than voltages with full harmonics. So far, there are no standards that lay down limit values for systems above 110 kV, but 0.2 % (of the nominal voltage) is used in Norway and 0.5 % in Sweden. Voltages and intermediate harmonics are generated by arc furnaces, welding equipment and fast frequency converters.

2.2 HVDC[1]

- Every new HVDC link should be designed so that it has no negative effect on existing equipment connected to the grid. Examples of negative effects are SSR (sub-synchronous resonance), rapid voltage variations, harmonic voltages and interference with telecommunications. In addition, the link should not have a negative effect on system operation. Examples of possible system operation problems are insufficient ability to tolerate voltage dips or exaggerated input/output of reactive power. A bipolar link should also be designed so that the risk of losing both poles for the same reason is as low as possible.
- It should be possible within the frequency range 49.9-49.5 Hz for the HVDC interconnections to have frequency-dependent regulation with droop. Frequency-controlled step or ramp variation of the power is not permitted in this frequency range when it is used in droop regulation.
- Any other regulation of emergency power must be based on the conditions that apply at the site. The question also concerns the affected TSOs.
- The owners of new HVDC interconnections are to notify the Operations Committee of the setting parameters for the regulating energy, ramps and emergency power in relation to existing HVDC links according to agreements with the TSOs in Nordel.

2.3 Connecting grids

The connection must be set up in such a way that the quality of the Nordic electric power system is not affected.

2.3.1 Take-out and surplus of reactive power

TAKE-OUT AND SURPLUS OF REACTIVE POWER					
Subject	**Denmark**	**Finland**	**Iceland**	**Norway**	**Sweden**
Tapping from the grid	Balance per voltage level. MVAr transport is minimised.	Balance per voltage level. Transport is minimised with the aid of a "window" (tan φ = 0.04-0.16). MW loss is minimised.	PF (cos φ) = 0.90 at 132 - 220 kV. PF (cos φ) = 0.85 < 132 kV. + "fine" 1)	There must be no transport of MVAr, which has a negative effect on the voltage.	Balance per voltage level. Not measured.
Reactive surplus	Reactors etc. ~ intact grid after 50 % load shedding 2)	Reactors etc. ~ intact grid with three in reserve		Reactors etc. ~ Grid intact	

1) From 1998, the limits are changed to 0.95 and 0.9 respectively.
2) The eastern part synchronous to the Nordel grid. The western part has own rules corresponding to the demands from the synchronous UCTE grid.

[1] Written in the light of draft for Nordel recommendation.

3 Production

3.1 Terms

3.1.1 Types of production plant

Definitions:

Gas turbine unit	Production plant powered by air and combustion gases to generate electric power. One generator with one or more gas turbines. There are two types: jet and industrial.
Combined plant	Steam turbines and gas turbines that use the same fuel cycle, in which exhaust heat from gas turbines is used to produce steam for steam turbines.
Condensing power plant	One or more thermal power units in the same production plant, which produce only electricity.
Combined heating and power (CHP) plant	One or more thermal power units in the same production plant, powered by fossil and/or bio fuel and which combine the production of electricity and heat, which is used for district heating or for an industrial process.
Nuclear power plant	One or more thermal power units in the same production plant, which produce only electricity and which are powered by nuclear fission in a reactor. There are two types: the pressurised water reactor (PWR) and the boiling water reactor (BWR).
Hydropower unit	Turbine and generator coupled together and powered by water.
Hydropower station	One or more hydropower units in the same production plant.
Wind power unit	Turbine and generator coupled together and powered by wind.
Wind power farm	One or more wind power units with a common connection to the power grid.
Thermal power unit	Production plant powered by uranium, fossil and/or bio fuels to generate electric power. Turbine and generator coupled together, powered by steam from a boiler or a reactor.
Thermal power block	One or more thermal power units powered from a common boiler or reactor. Combined heating and power plants are included in thermal power blocks.

3.1.2 Other terms

Definitions:

House load operation	Operation of a unit with its own auxiliary machinery as its only load, when the unit is disconnected from the external power grid.
Rated field voltage	The field voltage of a generator at rated load and nominal operating voltage.
Rated load	Simultaneous nominal active and reactive production.
Nominal active power	Nominal design power for electricity production.
Nominal operating voltage	The operating voltage of the connecting grid, which is used as a design precondition when planning the unit.
Nominal generator voltage	The design voltage of the generator.
p.u.	"Per unit": a term which states the size relative to a nominal value which must have been defined in each individual case.

Frequency response	The ratio between power change and frequency deviation when automatic frequency control is used.
Droop	The inverse of frequency response, i.e. the ratio between frequency deviation and power change.
Synchronous generator	A generator whose rotation speed follows the frequency of the connecting grid.

3.2 General requirements to be met by thermal power and hydropower

Requirements:

- Thermal power plants (Norway, Sweden and Denmark > 100 MW, Finland > 50 MW)
- Hydro power plants (Norway > 10 MW, Sweden and Finland > 50 MW)

The national requirements may be stricter than the requirements stated below.

3.2.1 Automatic frequency control

The production plants must be capable of automatically contributing to frequency regulation of the electric power system with a frequency response in the range 0.25-1 p.u. power/Hz, which corresponds to a droop of 8-2 %, at a frequency variation of 50 ± 0.1 Hz. The locally measured grid frequency or the rotation speed of the plant is used as a control signal.

3.2.2 Turbine regulator, set point

The unit controller shall have an adjustable frequency set point in the range from 49,9 Hz to 50,1 Hz. The set point resolution shall be 0,05 Hz or better. For large thermal power plants an adjustable frequency dead band of the unit controller within the setting range of 0-50 mHz is acceptable.

3.2.3 Tolerance to frequency variations

<u>Frequency Range 49 Hz to 51 Hz</u>

It shall be possible to operate the unit continuously at full output power within the grid voltage range of 90- 105% of the normal voltage, and at any frequency between 49 and 51 Hz. A maximum operating time of 10 hours/year and duration of 30 minutes maximum per case can be assumed within the frequency range of 50.3-51 Hz. At a frequency above 50.3 Hz a small power reduction is accepted, if stable operation at full power can be re-established when the frequency again drops below this value. See Figure 1.

<u>Frequency Range 49 Hz to 47.5 Hz</u>

It shall be possible to operate the unit under disturbance conditions for 30 min within the grid voltage range of 95-105 % of the normal voltage, at any frequency down to 47.5 Hz. The output power may then be reduced by 0 % at 49 Hz and a maximum of 15 % at 47.5 Hz, and by a value found by linear interpolation at frequencies between these two limits. Efforts should be made to lower this reduction in output power, if this can be achieved without high additional costs.

<u>Transitory Frequency Variations 51 Hz to 52 Hz</u>

It shall be possible to operate the unit for 5 sec during transitory conditions of the network in connection with exceptional disturbances within the grid voltage range of 95-105 % of normal voltage at any frequency between 51 and 52 Hz. During such transients the power may be reduced, if stable operation at full power can be re-established when the frequency again drops below 50.3 Hz.

Frequency Range 51 Hz to 53 Hz
On a separate electrical network it shall be possible to operate the unit at strongly reduced output power within the grid voltage range of 95-105 % of normal voltage, at any frequency between 51 and 53 Hz for 3 min.

Frequency Below 47.5 Hz
The unit may be tripped from the network at frequencies below 47.5 Hz. The unit shall then be capable of changing over to house load operation. However, this should not take place instantaneously, the time delay being determined by the design limits of the unit and so that reliable changeover to house load operation will be obtained.

Frequency Gradients
The control system shall be designed so that the unit will not trip because of the transient frequency gradients occurring in case of short-circuit on the high voltage network to which the unit is connected.

3.2.4 Tolerance to voltage variations

Grid Voltage Range 90 % to 105 % of Normal Voltage
It shall be possible to operate the unit continuously at full load within the frequency range of 49-51 Hz and at a grid voltage between 90 and 105 % of normal voltage. At a frequency above 50.3 Hz, a small power reduction is accepted, if stable operation at full power can be re-established when the frequency again drops below this value. A maximum operating time of 10 hours/year and a duration of 30 minutes maximum per case can be assumed within the frequency range of 50.3-51 Hz. (Same requirements as in Section 3.2.3 (Frequency range 49 Hz to 51 Hz). See Figure 1.

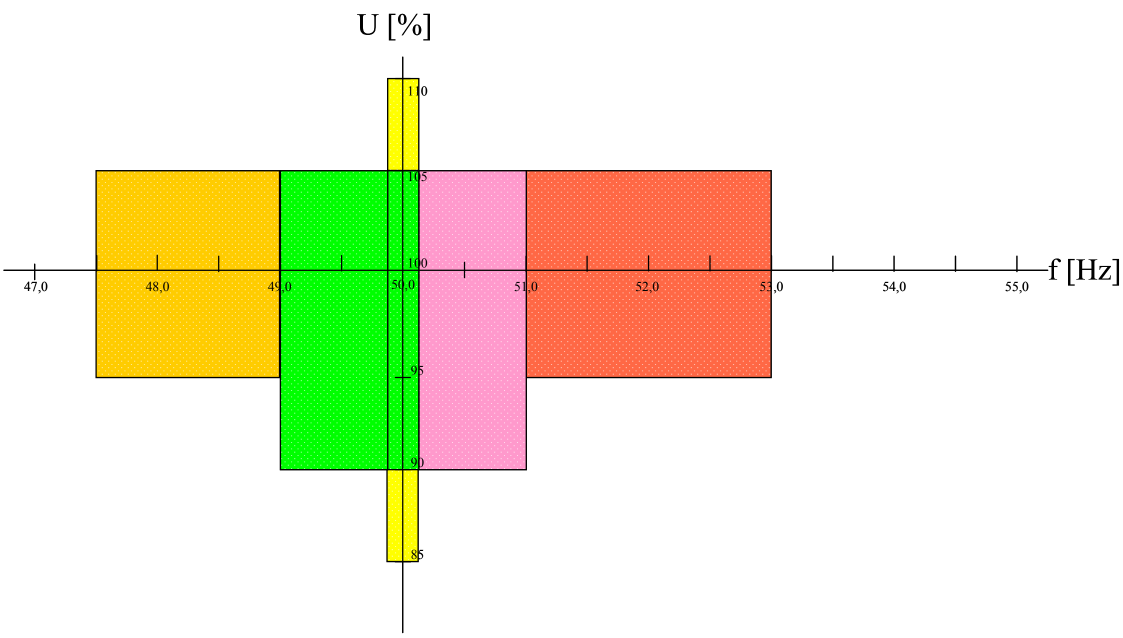

Figure 1 Performance requirements for power production in relation to frequency and voltage

Grid Voltage Range 85 % to 90 % of Normal Voltage
It shall be possible to operate the unit for 1 hour within the frequency range of 49.7-50.3 Hz at a grid voltage between 85 and 90% of the normal voltage, and an output power reduction of up to 10 % of full output may then be acceptable.

Grid Voltage Range 105 % to 110 % of Normal Voltage
It shall be possible to operate the unit for 1 hour at a frequency within the range of 49.7-50.3 Hz and at a grid voltage between 105 and 110 % of normal voltage. A small output power reduction may then be acceptable (approximately 10%).

Consequences of Nearby Grid Faults
a) Ability to Withstand Mechanical Stresses Due to Line Side Faults
Thermal power units shall be designed so that the turbine generator set can withstand the mechanical stresses associated with any kind of single-, two- and three-phase earth or short circuit fault occurring on the grid on the high voltage side of the step-up transformer. The fault can be assumed to be cleared within 0.25 sec. Neither damage nor need for immediate stoppage for study of the possible consequences are allowed.

b) Line Side Faults of Clearing Time up to 0.25 Sec
The unit shall be designed so that it remains connected to the grid and continues its operation after isolation of line side fault within 0.25 sec.

Thermal power plants > 100 MW in Denmark East (synchronous to the Nordel grid) shall fulfill the above demands. Thermal power plants > 100 MW in Denmark West (synchronous to the UCTE grid) shall fulfill UCTE demands. (Clearing time 0.15 Sec and the demands are to the line side of the generator transformer.) For smaller thermal power plants and wind power plants the demands are weaker see detailed specifications. (Chapter 6 of TF 3.2.3 will be changed at next revision.)

c) Deep Voltage Transient
The units shall be designed so that they can withstand the following line side voltage variation resulting from faults in the grid, without disconnection from the grid:

- step reduction to 0 % of the line side voltage lasting for 0.25 sec,
- followed by linear increase from 25 % to 90 % in 0.5 sec,
- followed by constant line side voltage 90 %.

Consequently, only a small power reduction can be accepted.

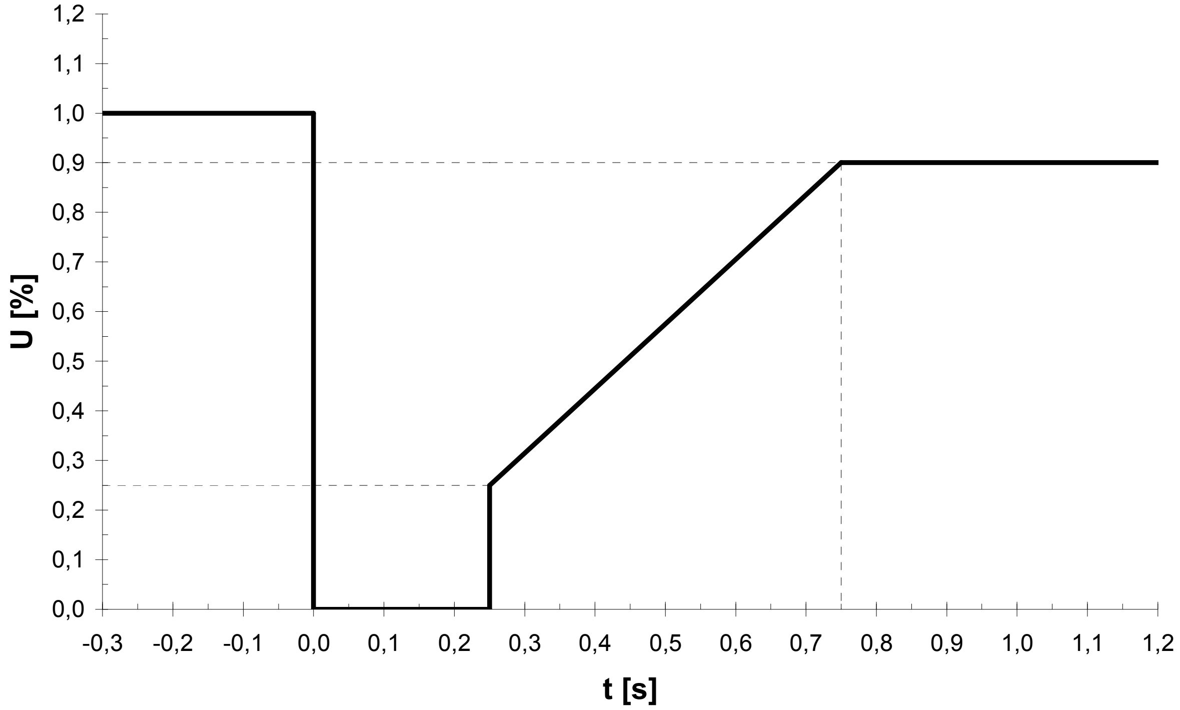

Figure 2 Deep voltage transient in line side voltage caused by a network fault

It shall be noted that the design criteria for the voltage protection may deviate, as the unit must manage several kinds of other faults that may occur in the generators/power grid.

<u>Large Voltage Disturbances</u>
The unit may be disconnected from the power system, if larger voltage variations or longer durations than those for which the unit has been designed occur, and shall, in each case, be disconnected if the unit falls out-of-step.

The unit and its auxiliary power system shall be designed for such voltage variations that a safe changeover to house load operation can take place after disconnection from the network.

<u>Reactive Power Output at Low Voltages</u>
Thermal power units shall be equipped with such excitation systems and shall be designed for such a power factor that the generator will be capable of providing a reactive power output of about the same magnitude as the rated active power output for 10 sec, in conjunction with network disturbances and at a generator busbar voltage of 70 % of the rated generator voltage.

<u>Reactive Power Capability</u>
The thermal power units shall be able to generate and to consume reactive power in adequate amounts within their capabilities for the voltage control of the power system. At normal grid voltage the generators shall be designed to operate within the limits of reactive power output and input defined by the capability diagrams of the generators or by stable reactive droop.

At grid voltages higher than the normal voltage the under-excited capability of the generators shall be fully available according to the capability diagram or static stable reactive droop, whichever is more limiting.

The countries' MVAr requirements for the power plants			
	MVAr requirements for new building 1)		Operating voltage range
	Production	Consumption	
Danish thermal power	tg φ = 0.4 at 420 kV	tg φ = - 0.2 at 400 kV	380 - 420 kV
Swedish thermal power	1/3 at U>90% Ugen 3)	0 3)	395 - 420 kV
Finnish thermal power	cos φ = 0.9 at 360…420 kV 2)	cos φ = 0.95 at 400…420 kV 2)	380 - 420 kV
Swedish hydro power	1/3 at U>90% Ugen 3)	-1/6 3)	395 - 420 kV
Finnish hydro power	cos φ = 0.9 at 360…420 kV 2)	cos φ = 0.95 at 400…420 kV 2)	380 - 420 kV
Norwegian hydro power	cos φ = 0.86 2)	cos φ = 0.95 2)	390 - 420 kV
Icelandic hydro power			

1) The countries combine the MVAr requirements and associated voltages at the generator terminals and busbar in different ways.
2) Power factor (cos φ) is measured at the generator terminals.
3) MVAr measured at the busbar and Ugen as nominal generator voltage transformed to busbar side of transformer.

The information above illustrates how the MVAr requirements affect the most costly component (the generator). Any supplementary requirements that the MVAr requirements should be met at set voltages for the busbar affect the systems properties of the power plants and the design of the plant, but have only a marginal effect on the price of the plant, provided that this is specified during the project phase. This may, for instance, apply to the ratio of the machine transformer and the winding connections for the internal consumption transformer. The actual operating point is determined depending on the actual operating situation in the transmission network.

3.2.5 Generator and voltage regulator characteristics

Generators

The generator reactance shall be as low as technically and economically possible in order to support the stable droop and reactive power control.

Each generator shall be capable of operating on the rated active power continuously at power factor down to at least 0.95 under-excited, and 0.9 over-excited. This shall be possible in connection with voltage and frequency conditions as described in Tolerance to voltage variations (90-105 % of normal voltage). At under-excited conditions normal grid voltage is applied instead of 90 % voltage.

Voltage Control

The preferred dynamic characteristics for steady state are defined in a measurable way as follows:

The 10 % step response of generator voltage is recorded in no-load conditions, disconnected from the grid. The set value of the voltage is changed by plus and minus stepwise changes causing change of generator terminal voltage from 95 to 105 %, and from 105 to 95 %. In both cases the step response of the generator terminal voltage shall be as follows:

- response is non-oscillating,
- rise time from 0 to 90 % of the change is 0.2-0.3 s in case of static exciter, or in case of brush less exciter: 0.2-0.5 s at a step upwards, 0.2-0.8 s at a step downwards,
- overshoot is less than 15 % of the change.

PSS, Power System Stabiliser
PSS shall be included in each generator. The PSS shall be tuned to improve the damping of the oscillations of generator and power system, especially the damping of low frequency (0.2-1.0 Hz) inter-area oscillations.

Additional Voltage Control Equipment
Current limiters (for generator rotor and stator) shall have invert time characteristics to utilise the generator over current capability to a good extent for various network conditions.

Voltage Control Priority
The normal way of operation is automatic control of generator voltage with the effects of reactive current droop. In case of needs for different type control, like control according to power factor or reactive output, these additional controls shall affect at lower priority than the regulation of voltage.

Island Operation
In case of very serious (and exceptional) disturbances, where the power system is separated into smaller grids, the units shall also initially be capable of performing the above-mentioned power changes (upwards or downwards), and then achieving stable operation and normal power control capability according to Section 3.3.3.

3.2.6 Verification

To the largest possible extent the specifications should be verified by full-scale test. This test should be made by the owner at commissioning and upon request from the TSO. Recordings of data from actual operation should be reviewed regularly in order to prove compliance with the specification.

Verification during Commissioning
This verification shall include:

- Full output power
- Minimum load
- Overload capacity
- Starting time
- Load following
- Power response rate including range
- Power step change
- Deep voltage transients by short circuit (if possible)
- Changeover to house load operation
- House load operation for 1 h
- Step response of generator voltage
- PSS test

3.3 Operational performance specifications for thermal power units > 100 MW

3.3.1 Operational characteristics

Minimum Output
The minimum output power shall be as low as possible. As a practical guideline, the minimum output power should be 40 % of full output power in coal-fired units, 20 % of full output power in oil-fired units, and 20 % of full output power in nuclear units.

Overload Capacity
Fossil-fired units should be prepared for overload capacities only to the extent that it is intrinsically available. For a steam turbine unit this could be the bypassing of high-pressure preheaters.

The overload capacities should only be utilised to a certain limit only, because of reductions in the efficiency and/or the lifetime of the unit.

The unit including auxiliary equipment should be designed to utilise these overload capacities up to 2 h/day and up to 500 h/year. No overload capacity is specified for nuclear power units.

Starting Time
For all types of thermal power units, the starting time shall be defined according to planned utilisation. In addition, the following guidelines shall apply to gas turbines for emergency and peak load generation, from rolling-up to full output power:

- gas turbines of jet engine type 3 to 3.5 minutes
- industrial gas turbines 10 to 15 minutes.

House Load Operation
House load operation is the unit operating with its own auxiliary supply as the only load.

3.3.2 Power control equipment characteristics

Operational Modes
The change of output power of a thermal power unit at the rates and within the ranges specified, during normal control and during disturbances control, is normally activated as follows:

- By manual operation
- By the unit controller

The unit controller shall have an adjustable frequency set point in the range from 49.9 Hz to 50.1 Hz. The set point resolution shall be 50 mHz or better.

The droop set point shall be adjustable in the range from 2 % to 8 %. The normal operation is generally with setting in the range from 4 % to 6 %.

An adjustable frequency dead band of the unit controller within the setting range of 0-50 mHz is acceptable. It shall be possible to disengage this dead band.

Power Step Change Limiter
The units shall be equipped with adjustable devices for limiting the magnitude and rate of the power change, so that it will be possible to set these set points at any values from zero up to the maximum specified, both for normal conditions and for disturbance conditions.

Power Control - Normal Operation and Disturbances
The required power output during normal operation is the manually preset power output, modified by a frequency-sensing unit controller (or turbine governor) and this power output shall meet the specifications in Section 3.3.3(Power response capability during normal operation of the power system).

The need for disturbance control shall be governed by frequency-sensing equipment (e.g. consisting of a frequency relay set at a certain value below normal frequency). The power output shall meet the specification in 3.3.4 (Power response capability during power system disturbances) when the unit is operated under these conditions.

3.3.3 Power response capability during normal operation of the power system

Load Following
All condensing units shall be designed so that they can be used for daily and weekly load following during certain periods of the year, using the rates of load change specified in the following.

The units shall also be designed so that, if necessary, they can participate in following the occasionally varying loads that cause frequency variations on the interconnected power system. This implies that the units shall be capable of accommodating power changes without intervals by plus or minus 2 % of full output within periods of 30 sec. The units shall be capable of performing these changes within the ranges specified. Power changes for nuclear units may be agreed with the grid operator to be less than plus or minus 2 %.

Power Response Rate and Range - Oil and Gas
Oil-fired and gas-fired units shall be designed for a power response rate of at least 8 % of full power per minute. The above power response rate of change shall be applicable to any range of 30 % between 40 % and 100 % of full power according to the load schedule. The power response rate may be limited to the maximum power response rate permissible for the turbines or the steam boilers in the range below 40 % and above 90 %.

Power Response Rate and Range - Coal
Coal-fired units shall be designed for a power response rate of at least plus or minus 4 % of full power per minute. The above power response rate of change shall be applicable to any range of 30 % between 40 % and 100 % of full power according to the load schedule. This range may be restricted to 20 % in certain cases. The power response rate may be limited to the maximum power response rate permissible for the turbines or the steam boilers in the range below 60 % and above 90 %.

Power Response Rate and Range - PWR Nuclear
PWR nuclear power units shall be designed for a power response rate of at least plus or minus 5 % of full power per minute within the output range of 60 % to 100 % of full power. At outputs below 60 %, the power response rate may be limited to the maximum power response rate permissible for the turbines.

Power Response Rate and Range - BWR Nuclear
BWR nuclear power units shall be designed for a power response rate per minute of at least plus or minus 10 % of the initial output value. This shall be maintained throughout all the output range within which the power can be controlled by the speed of the main circulation pumps. This output range shall be at least 30 % of the initial output power. In the remainder of the power range between minimum load and full load, the power response rate shall be at least 1 % of full power per minute.

Comment on requirements for nuclear power units: The power response rates of the units equipped with standard versions of light water reactors are usually sufficient. However, it should be noted that the power response rate is subject to some restrictions at the present time, due to the current design of fuel elements. It is expected that these problems will be solved, and the units should therefore be designed to conform to the recommended power response rates. However, in order to limit the stresses imposed, the power changes during normal daily and weekly load following should be carried out gradually over a period of about two hours.

3.3.4 Power response capability during power system disturbances

Instantaneous Power Response
The demand from the power system is that the instantaneous power response shall be available within 30 sec after a sudden frequency drop to 49.5 Hz. Half of that power response shall be available within 5 sec after the frequency drop.

Power Step Change - Fossil Fuel
Fossil-filed thermal units shall be designed with an operating mode allowing an instantaneous step change in output power of at least 5 % of full output within the range of 50-90 % when requested. Half of that power shall be available within 5 sec after the frequency drop. Units without or with only one reheater shall be designed in such a manner that this power step will be accommodated within 30 sec. If a unit includes more than one reheater, a further delay corresponding to the time constants of such additional reheaters is acceptable.

Power Step Change - Nuclear
PWR nuclear power units to which the power change signal is applied directly to adjust the turbine control valve shall be designed so that a power step of 10 % of full power can be accommodated within 30 % of the power range. BWR nuclear power units operating on pressure control shall be designed so that, within the range of pump control, they will be capable of accommodating a power change of 10 % of the initial value within 30 sec.

Subsequent Power Response Rate
After the power step changes specified above, thermal power units shall also be capable of accommodating a load change at the rates specified in 3.3.3 (Power response capability during normal operation of the power system). However, the total change in load may then be limited to the values also specified in 3.3.3.

Spinning Disturbance Reserve
All units of the condensing type shall be made so that they at times can be used as spinning disturbance reserves and then perform the above mentioned power variations, if serious disturbances occur on the grid.

3.3.5 House load operation

Design Characteristics

All power units shall be designed to change over safely to house load operation from conditions as specified in 3.2.3 (Frequency range 51 Hz to 53 Hz and Frequency below 47.5 Hz), and in 3.2.4 (Large voltage disturbances).

Operating Time

Thermal power units shall be designed so that they can operate in house load operation for at least 1 h. Nuclear power units shall be capable of operating in house load operation for a duration determined by the nuclear safety conditions.

3.4 Specifications for thermal power units < 100 MW

Below 100 MW and above 25MW

Minimum output: All the small power stations shall fulfil the regulation given in 3.3.1 irrespective of the type of primary fuel.

Overload capacity: Efforts should be made to observe this regulation, but observance is not demanded.

Starting time: Regulation given in 3.3.1 shall be fulfilled.

Operational modes and Power step change limiter: Regulation given in 3.3.2 shall be fulfilled.

Power control - normal operation and disturbances: Is not required to observe according to the abovementioned considerations.

Load following and Power response rate and range: Regulation given in 3.3.3 shall be fulfilled.

Instantaneous power response and Power step change for fossil fuel: Regulation given in 3.3.4 shall be fulfilled.

Power step change for nuclear, subsequent power response rate, Spinning disturbance reserve and Island operation: Are not relevant to small power stations.

Tolerance to frequency variations: A voltage profile as shown in Figure 2, in the transmission network or in the regional distribution network should not cause tripping of power stations.

Deviations of frequency and voltage within the hatched area on Figure 1 should not cause tripping of power stations. A reduction of the active production by up to 20 % is acceptable. The power stations should be able to tolerate frequencies up to 53 Hz.

Tolerance to voltage variations: Is not required to observe according to the above mentioned considerations. A quick start-up after tripping is desirable but is not demanded generally. Regarding the starting times the following directions can be given:

After release	30 min
After an outage time of 10 h	90 min
After an outage time of 30 to 50 h	120 min

As for unmanned plants another 120 minutes may pass before the personnel can arrive at the power station. It should be possible to start up and fully load gas turbine plants within 30 minutes even after a long outage time. It should be mentioned that the power that is at disposal after 15 minutes in the national systems can be calculated as part of the fast reserve.

Generator and voltage regulator characteristics, House load operation and Verification: Are not required

Below 25 MW
To these plants it applies that the requirements that it is reasonable to demand complied with depend on the mode of operation, manning and type of fuel.

Plants in the range 1 MW-25 MW

Minimum output: All the power stations shall fufill the regulation given in 3.3.1 irrespective of the type of fuel.

Overload capacity: Efforts should be made to observe this regulation, but observance is not demanded.

Starting time: Regulation given in 3.3.1 shall be fulfilled..

Operational modes and Power step change limiter: Regulation given in 3.3.2 shall be fulfilled. for power plants in the range 10-25 MW (In case of solid fuel fired plants observance may be difficult. No demands on plants in the range 1-10 MW.)

Power control - normal operation and disturbances: Is not required observed.

Load following and Power response rate and range: Regulation given in 3.3.3 shall be fulfilled. for power plants in the range 10-25 MW. (No demands on plants in the range 1-10 MW)

Instantaneous power response and Power step change for fossil fuel: Regulation given in 3.3.4 shall be fulfilled.

Power step change for nuclear, subsequent power response rate, Spinning disturbance reserve and Island operation: Are not relevant to small power stations.

Tolerance to frequency variations: A voltage profile as shown in Figure 2, in the transmission network or in the regional distribution network should not be allowed to cause tripping of power stations.

Deviations of frequency and voltage within the hatched area on Figure 1 should not be allowed to cause tripping of power stations. A reduction of the active production by up to 20 % is acceptable. For solid fuel fired plants of the 2nd category it may be difficult to comply with the requirement in the range from 47.5-49 Hz. The power stations should be able to tolerate frequencies up to 53 Hz.

Tolerance to voltage variations: Is not required observed. But a quick start-up after tripping is desirable. Gas turbine plants should be able to start automatically with the alternative of remote operation when the voltage is stable after a network fault causing tripping of the plant. For solid fuel fired plants of the 2nd category no requirements are made.

Generator and voltage regulator characteristics, House load operation and Verification: Are not required.

Plants < 1 MW
Local conditioned requirements are usually made. However, the power stations should be capable for short periods of time of tolerating frequencies in the range from 47.5 Hz to 53 Hz.

3.5 Special requirements for hydropower

National rules apply to hydropower plants that are not covered by the Connection Code. In Norway there are national requirements for hydro power plants. In Finland General requirements to be met by thermal power and hydropower are used.

NORDEL CONNECTION CODE WIND TURBINES

1 Introduction

The Nordic Connection Code for wind turbines is a part of the Nordic Grid Code. The Nordic Grid Code shall provide the common framework for the TSO's (Transmission System Operator) and the actors, who are operating facilities connected to the Nordic electricity system.

The Nordic Connection Code outlines the minimum technical requirements that new wind turbines together with their supplemental installations have to fulfil at the connection point to the transmission network in order to provide for adequate safe operation and reliability of the interconnected Nordic Power System. The Nordic TSO's may publish connection codes for the electricity system within their responsibility having additional requirements.

It must also be emphasized, that all capabilities will not be exploited in all wind turbines at all times. Connection codes shall provide the capabilities and characteristics of system components are available when ever needed for safe and reliable system operation. The exploitation of the different system components and their capabilities is regulated by system operation codes.

2 Definitions

Connection point: Point in the transmission network, to which the **wind turbine** or **wind plant** is to be connected. This point is defined by the TSO.

Wind turbine: Complete system to transform wind energy into electricity and to transmit the electricity to the **connection point**.

Wind plant[1] : More than one **wind turbine** connected to the same **connection point**, possible sharing connection cable/line and other equipment.

All other definitions are according to IEC standard.

3 Scope of the connection code

The requirements must be met by all **wind plants** connected to the Nordic Power system[2]. All requirements are to be met at the **connection point**.

4 Active power control

It must be possible to control the active power production from the **wind plant**. The following control functions must be available

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[1] Wind Plant is a synonym to the commonly used Wind Farm.

[2] The TSO decides in each case whether wind plants smaller than 100 MW has to fulfil all requirements or they may be released to some extent according to the related impact to the interconnected Nordic system operation and security.

- An adjustable upper limit to the active power production from the wind plant shall be available whenever the wind plant is in operation. The upper limit shall control that the active power production, measured as a 10 minute average value, does not exceed a specified level and the limit shall be adjustable by remote signals. It must be possible to set the limit to any value with an accuracy of ±5%, in the range from 20% to 100% of the wind plant rated power.
- Ramping control of active power production must be possible. It must be possible to limit the ramping speed of active power production from the **wind turbine** in upwards direction (increased production due to increased wind speed or due to changed maximum power output limit) to 10% of rated power per minute. There is no requirement to down ramping due to fast wind speed decays, but it must be possible to limit the down ramping speed to 10% of rated power per minute, when the maximum power output limit is reduced by a control action.
- Fast down regulation. It must be possible to regulate the active power from the **wind turbine** down from 100% to 20% of rated power in less than 5 seconds. This functionality is required for system protection schemes. Some system protection schemes implemented for stability purposes require the active power to be restored within short time after down regulation. For that reason disconnection of a number of wind turbines within a wind plant cannot be used to fulfil this requirement[3] .
- Frequency control. Automatic control of the **wind turbine** active production as a function of the system frequency must be possible. The control function must be proportional to frequency deviations and must be provided with a dead-band. The detailed settings will be provided by the TSO.

5 Reactive power capacity

The **wind plant** must have adequate reactive capacity[4] to be able to be operated with zero reactive exchange with the network measured at the connection point, when the voltage and the frequency are within normal operation limits. See area A in figure 1, chapter 7.

6 Reactive power control

The reactive output of the **wind plant** must be controllable in one of the two following control modes according to TSO specifications:

1 . The **wind plant** shall be able to control the reactive exchange with the system. The control shall operate automatically and on a continuous basis. The wind plant shall be able to maintain acceptable small[5] exchange of reactive power at all active power production levels.

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[3] In a system having a limited number of wind turbines this is not a vital problem. But wind turbines are designed to stay in operation for 20 years or more, and the international trend is, that wind turbines in some periods will produce an increasing part of the total power production. It will eventual be a problem if not addressed in proper time.

[4] The reactive capability need not to be installed inside each wind turbine, but may be installed in one or more separate devices connected to the system at the same connection point as the wind turbines.

[5] The TSO defines the acceptable limit according to local system conditions

2 . The **wind plant** must be able to automatically control its reactive power output as a function of the voltage in the connection point with the purpose of controlling the voltage.

The detailed settings of the reactive power control system will be provided by the responsible TSO

7 Dimensioning voltage and frequency

The system operating conditions that the **wind plant** must be able to meet are outlined in the following figure:

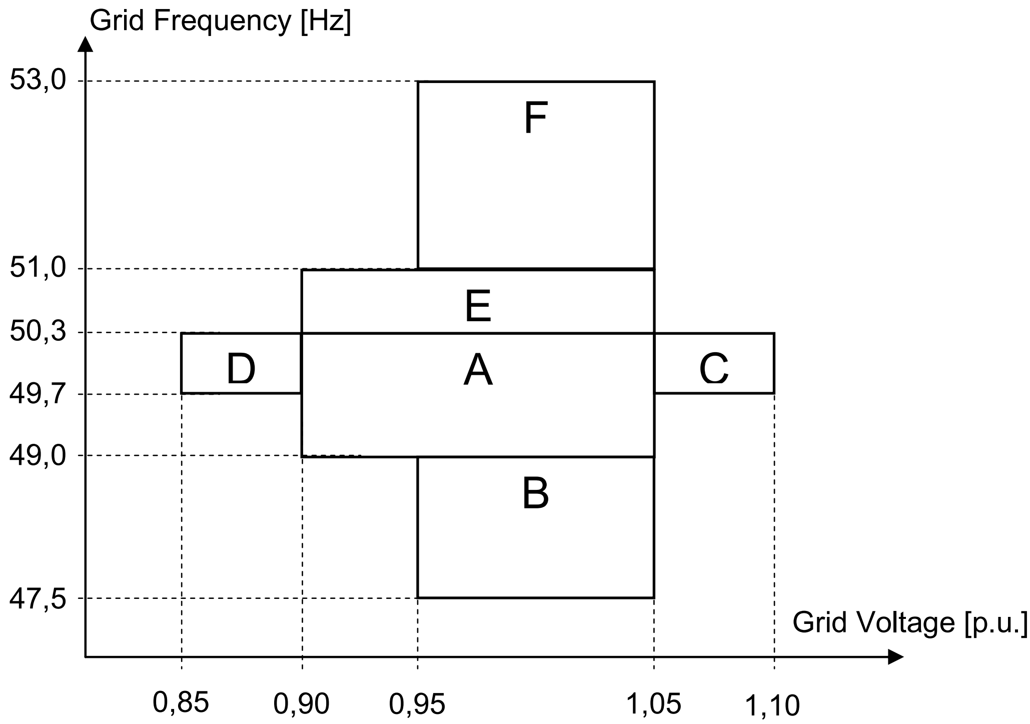

Figure 1. Performance requirements in relation to voltage and frequency. The reference for p.u.value shall be defined by TSO.

When the voltages and frequencies are within the rectangular areas shown in the figure, the following requirements applies:

A: Normal continuously operation. No reduction in active or reactive capability is allowed due to system voltage and frequency.

B: Uninterrupted operation in minimum 30 minutes shall be possible. The active output is allowed decreased as a linear function of the frequency from zero reduction at 49.0 Hz to 15% reduction at 47.5 Hz.

C: Uninterrupted operation in minimum 60 minutes shall be possible. The active output may be reduced 10%.

D: Uninterrupted operation in minimum 60 minutes shall be possible. The active output may be reduced 10%.

E: Uninterrupted operation in minimum 30 minutes shall be possible. The possible active output is allowed to be slightly reduced. (The total duration of these operating conditions is normally not more than 10 hours per year).
F: Uninterrupted operation in minimum 3 minutes shall be possible. The active output may be reduced to any level, but the turbines must stay connected to the system.

8 Operational characteristics during grid disturbances

The **wind plant** must be able to continue operation during and after disturbances in the transmission network. This requirement applies under the following conditions:

- The **wind plant** and the **wind turbines** in the **wind plant** must be able to stay connected to the system and to maintain operation during and after dimensioning faults in the common Nordic transmission system. In each area, the TSO defines which parts of his system are included in the Nordic transmission system. (It is normally defined by voltage level and depends on parallel operation with the highest voltage levels. It is always above 100 kV)
- The **wind plant** may disconnect from the system, if the voltage in the connection point during or after a system disturbance do fall below the levels shown in the following figure 2[6].

The fault duration, where the voltage in the connection point may be zero, is 250 milliseconds. The voltage at the wind turbine generator terminals will be higher due to transformer and network impedance.

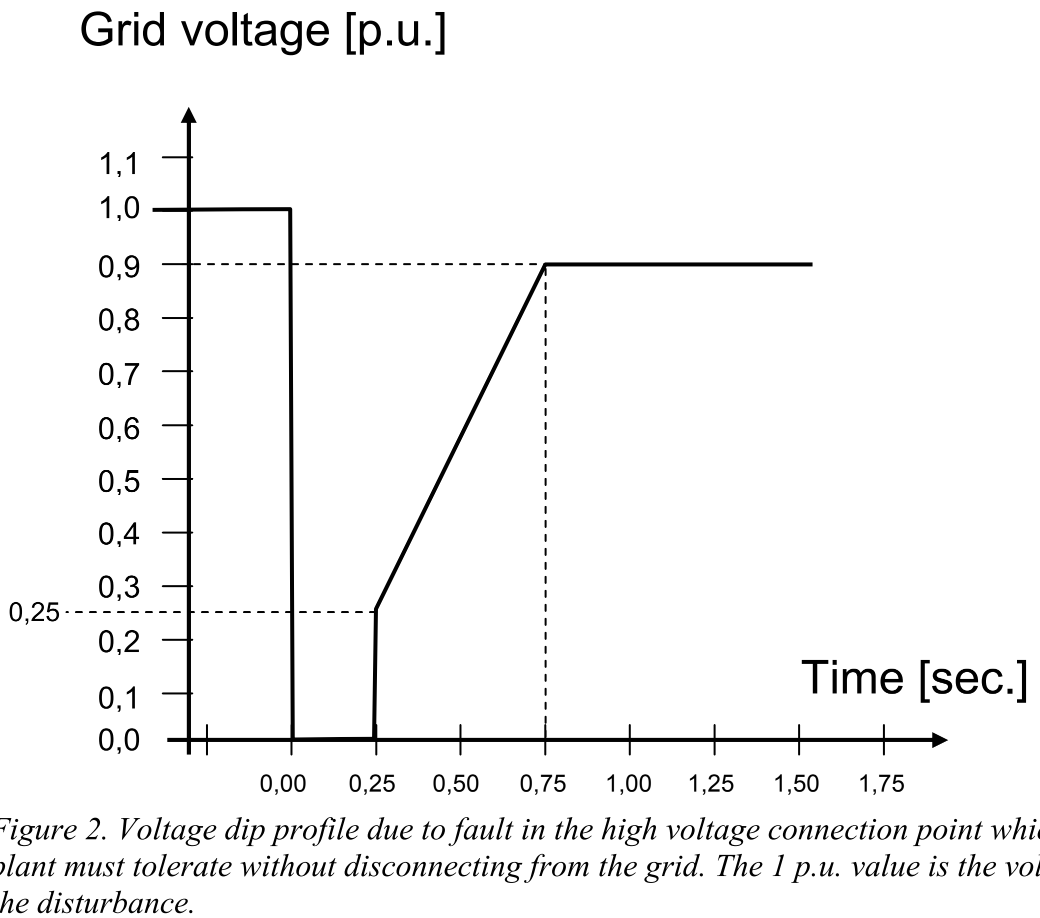

Figure 2. Voltage dip profile due to fault in the high voltage connection point which the wind plant must tolerate without disconnecting from the grid. The 1 p.u. value is the voltage before the disturbance.

[6] The rise-time of the voltage is highly dependent on the local system characteristics, i.e. short circuit capacity. The TSO may decide to use a different curve in his own area to ensure adequate system security.

9 Start and stop

It is recommended, that the **wind plant** is designed so that the **wind turbines** within the **wind plant** does not stop simultaneously due to high wind speeds.

10 Remote control and measurements

Wind plants must be controllable from remote locations by telecommunication. Control functions and operational measurements must be made available to the TSO on request.

The TSO in each area specifies the required measurements and other necessary information to be transmitted from the wind plant.

11 Test requirements

Prior to the installation of a **wind turbine** or a **wind plant**, a specific test programme must be agreed with the TSO in the area. The test programme shall be the documentation of the capability of the **wind turbine** or **wind plant** to meet the requirements in this connection code.

As a part of the test programme, a simulation model of the **wind turbine** or **wind plant** must be provided to the TSO. The model shall be provided in a format given by the TSO, and the model shall show the characteristics of the **wind turbine** or **wind plant** in both static simulations (load flow) and dynamic simulations (time simulations). The model shall be used in feasibility studies prior to the installation of the **wind turbine** or **wind plant** and the commissioning tests for the **wind turbine** or the **wind plant** shall include a verification of the model.

The following documents have been included in this chapter:

Document	*Status*
Data exchange agreement between the Nordic transmission system operators (TSOs) 2006	*Binding agreement*

The following national documents deal with the Data Code:

Document	*Status*

The TSOs in the Nordic countries have entered into a data exchange agreement, Data exchange agreement between the Nordic TSOs. The data exchange agreement contains a basis and data for a grid model and joint operation model, which was drawn up jointly by the TSOs. The agreement is reproduced in this section.

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DATA EXCHANGE AGREEMENT BETWEEN THE NORDIC TRANSMISSION SYSTEM OPERATORS (TSOS)

Framework for the exchange, use and distribution of power system data

1 Introduction

The liberalisation of the energy sector in Europe has made it necessary to re-evaluate a number of old co-operative relationships. However, operational reliability for an individual country is still dependent on the reliability of the composite system.

The primary purpose of formalised Nordic co-operation in the field of power system data is to create the best possible basis for system analyses of the interconnected Nordic power system for dealing with balance and capacity problems and for secure exploitation of the advantages of interconnected systems, as well as to achieve
savings in terms of time and resources.

A further important aim is to control the distribution of the models that are used to analyse the Nordic power system, i.e. the complete Nordic grid model and the multi area power market simulator.

Certain data are subject to preparedness-related restrictions in the individual countries or are of commercial interest. Data concerning production plants should be considered commercial, and must therefore be treated as confidential; for further information see § 4.

This document sets out the framework that shall control future activity, primarily the exchange, use and distribution of power system data for and in the form of the grid model and the multi area power market simulator, as well as access to analysis results.

2 Parties

The parties to the agreement are the Nordic TSOs, Energinet.dk (cvr no 28980671, Denmark)., Fingrid Oyj (Business ID 1072894-3, Finland), Statnett SF (NO 962 986 633 MVA, Norway), Affärsverket svenska kraftnät (Org. no.: 202100-4284, Sweden) and Landsnet (Registration no. 580804-2410, Iceland).

It is a precondition that the parties take part in the co-operation by virtue of their function as TSOs. The Planning Committee of Nordel administers the agreements.

3 Scope

The data exchange agreement applies to the basis of and data for the grid model and multi area power market simulator established jointly between the TSOs in Nordel.

Grid model
The term **grid model** refers to the power system data that are needed in order to carry out load flow and dynamic studies on all or parts of the Nordic power system including the non-synchronised power system on Jutland. If the need arises, data for an equivalent of the complete Nordic grid model and fault current studies can be included in the work of the working group.

The scope of the term "complete Nordic grid model" is specified in Appendix 1.

Multi area power market simulator
The term **multi area power market simulator** refers to the power system data needed to calculate the power and energy balances of the entire Nordic power system, including assessment of the plants' expected operation in the market.

The scope of the term "complete Nordic multi area power market simulator" is specified in Appendix 2.

Procedure
The procedure for the use and maintenance of the Nordel dataset is described in Appendix 4.

The procedure can be altered by unanimous decision of the Planning Committee.

4 Rules of confidentiality

If the data that the parties exchange with each other has not been published in the country to which it refers, the parties are obliged to treat the data confidentially as far as possible in accordance with the legislation in force in the respective country.

5 Internal use and use within Nordel

The grid model and the multi area power market simulator may be freely used for studies by the parties to the agreements or for studies that exclusively involve the parties to the agreements, either bilaterally or with several parties involved.

All results from internal use of the models are regarded as the property of the parties participating in the study. In the case of analyses whose results are of significance for another party to the agreement, that party will be kept regularly informed.

The grid model and the multi area power market simulator may be freely used in Nordel's studies.

6 Use of consultants

In cases where one of the parties to this agreement uses a consultant for advice on a study or to carry it out, and the consultant represents a party to this agreement in his name, the grid model or the multi area power market simulator or the anonymised model may be passed to the consultant subject to his signature to the agreement that governs the relationship, confirming that the consultant will treat the information in strict confidence, and will obey the same rules of confidentiality as apply to the relationship between the parties for the particular data in the country where this data was produced; see Appendix 3.

The consultancy agreement is entered into solely by the parties of that assignment. Results and background material are the property of the client (the party/ies). The other parties of this data exchange agreement are to be informed of such consultant agreements. The information is governed by the procedure in Appendix 4.

Agreements for consultant assistance may only be entered into with consultants who are accepted by the parties to this agreement. The consultant's name and a presentation of the consultant must be sent to the other parties for approval within two weeks. Accepted consultants can only use the models for studies carried out for one or more of the parties of this data exchange agreement.

Agreements with consultants must state that they do not obtain rights of use or ownership of results produced with the aid of data in accordance with this agreement; see Appendix 3.

7 Equivalents

Equivalents of the Nordic power system can be supplied to and used by third parties for their studies. In such cases, studies may be done by a third party. The complete grid model or the complete multi area power market simulator may be used by the parties to the agreement to create such equivalents.

An equivalent is a simplified version of the complete Nordic models (see Appendix 1 and Appendix 2). The aim is that the characteristics of the equivalent at the connection points should be the same as those of the complete model (in terms of load distribution, impedances and dynamic response, for example). It must not be possible to identify in the equivalent the internal relationships in the model.

8 Anonymised complete model

An anonymised complete model of the Nordic power system can be supplied to and used by third parties for their studies. In such cases, studies may be done by a third party. An anonymised complete model is a special case of an equivalent. An anonymised complete model may only be supplied after specific processing and consensus in the Planning Committee (see Appendix 3).

Results of studies (see definition in Appendix 3) are to be given to all parties in accordance with procedure.

9 Transfer and renegotiation of agreement

If restructuring takes place in one of the countries involved in the collaboration, agreements and information concerning this matter may be transferred to the organisation that is given responsibility for the system in the country in question.

If one of the above-mentioned parties wishes to renegotiate the agreement, this process must start not later than six months from the request to do so. Once entered into, an agreement remains valid until a new agreement comes into force.

10 The agreement is accessible to market actors

To create confidence that the TSOs are fulfilling their obligations, this agreement will be made accessible to the market actors, who are required to supply data. This can be done, for example, by placing the agreements on Nordel’s website, and by the parties to the agreement placing links to Nordel’s website on their own websites.

11 Breach

In so far as a party is in breach of the provisions of the agreement, that party is obliged, within one month of being required to do so in writing by the other parties to the agreement, to cease using data, and the agreement is thereafter terminated as regards the party in breach. During that month, no data may be copied or distributed.

12 Validity period and notice of termination of the agreement

By signing of this agreement the previous data exchange agreement of 27. June 2002 will expire.

The agreement is valid until further notice and ceases after unanimous agreement between the parties. Three months' notice of termination of the agreement may be given in writing by one of the parties to the agreement, with the effect that the party who gave notice withdraws from the agreement. The party giving notice undertakes to cease using all data, models and information about the systems of the other parties to the agreement that, through the agreement, is in the possession of that party within one week of notice to terminate the agreement.

After notice of termination of the agreement has been given, no data may be copied or otherwise transferred or distributed.

13 Filing of the agreement

The agreement is drawn up in one copy, which is filed by the active secretariat of Nordel. Each party must be provided with a duplicate of the agreement.

Helsinki 7.th. March 2006

<signature>	<signature>
Statnett, Øivind Rue	Svenska Kraftnät, Bo Krantz
<signature>	<signature>
Fingrid Oyj, Pertti Kuronen	Fingrid Oyj, Jussi Jyrinsalo
<signature>	<signature>
Energinet.dk, Peter Jørgensen	Landsnet, Eymundur Sigurdsson,

SCOPE OF DATA FOR THE COMPLETE NORDIC GRID MODEL

The Nordic grid model is data for the Nordic power system formatted on the format of the analysis software used in the model in accordance with the procedure, but the term also applies to the same data formatted for the format of other analysis softwares.

The term “power system data” comprises:

- All information stated in the definition of the data format of the analysis software used for studies with synchronous (positive-sequence), inverse (negative-sequence) and zero (zero-sequence) system data for 400 kV to 70 kV, possibly including equivalents for the connection of production and compensation installations at a lower voltage level and for the dynamic studies below:
    - ➢ Data for existing and future production, transmission and compensation installations including dynamic models.
    - ➢ Recorded or forecast data for active and reactive consumption in different operating situations, for instance high load and low load.
    - ➢ Production data for existing and future production plants in different operating situations.
    - ➢ Information about operational connection in different operating situations.
- Models and utility softwares developed and/or owned by the parties to the agreement and used in the studies
- Map material and drawing data that describe, or are used to describe, the geographical or electrical characteristics of the power system
- Written and electronic background material for creating and documenting the grid model

SCOPE OF DATA FOR THE MULTI AREA POWER MARKET SIMULATOR

The Nordic multi area power market simulator comprises data for analysis of the power balance, e.g. the power and energy balance for the Nordic power system. There are three main types of data:

Production data:
Production data is stated for the different types of production plant. These types may, for example, be subdivided into

- Hydro power
- Thermal power - condensing
- Thermal power withdrawal
- Thermal power, back-pressure – district heating
- Thermal power, back-pressure – industry
- Wind power

In addition, the plants are distributed geographically in accordance with the subdivisions in the transmission models; see below.

Technical data includes:

- Efficiencies
- Capacities
- Fuel type
- Availability
- Environmental conditions
- In addition, for wind power the energy conditions are stated in the form of time series suitable broken down by time; see below.
- For hydro power, the reservoir volume, draw-down limitations, and for certain analyses the relevant wind conditions, should be stated.

Financial data includes:

- Operating and maintenance costs

Further data: may include reserves (instantaneous, rapid), etc.

Consumption data:

- Annual consumption for electric power and for heating, when connected to a CHP plant
- Distribution of the consumption over the year – broken down by time, for example weeks and within the week into 3 to 8 load sections
- Additional material describing the maximum load situation
- Geographically distributed in accordance with the breakdowns in the grid models; see below

Grid and transmission data:

Transmission data is maintained on two levels of detail:

- For basic energy balances: here a DC approximation is needed, with the Nordel area subdivided into a modest number of areas with transmission between them. Data comprises transmission capacities, losses, availability, grid tariffs.

- For further assessments, e.g. to be able to assess the plausibility of the subdivision in the DC approximation, there must be a more detailed description. Subdivision into areas and design of the grid model must be coordinated with the Nordel Grid Group.

DRAFT AGREEMENT – POWER SYSTEM DATA – USE OF CONSULTANT ASSISTANCE

Agreement on the handling of power system data from TSO(s) to consultancy companies for use in the study "Study"

The consultancy company is referred to below as the recipient.

The transfer of power system data is subject to the following provisions:

1. All power system data received must be treated as confidential information, and the recipient must sign a declaration of confidentiality which contains, among others, the same clause as in § 4 of the agreement.
2. All power system data supplied by TSOs may only be used for the above-mentioned study.
3. When the recipient has completed the above-mentioned study, the received power system data must be deleted from the media on which it was stored (paper, magnetic tape, hard disk, backup etc). This must be confirmed not later than two months after completion of the study. Power system data must not be stored on media, where backup routines make the said deletion impossible.
4. The recipient will appoint one person who is responsible for the received information / power system data and who will ensure that the content of this agreement is respected and complied with.
5. Individuals at the recipient's company who are given access to the supplied power system data in order to carry out the study must be informed of the content of this agreement.
6. The recipient shall ensure that their computer and network security is sufficient (i.e. conforms to the de facto standard of the sector).
7. Parties to the agreement may approach the software supplier about software-related and model-related questions and in connection with this attach a data model. In this context, the software supplier has the status of a consultant. If the answer is of general interest, the parties to the agreement must be informed.
8. Results and background material from the study are the property of the client.
9. The content and scope of the term "power system data" are defined in Appendix 1.
10. The parties to the data exchange agreement between the TSOs are entitled to information about the content and results of the abovementioned study.

Sections 1 to 10 of this appendix apply to studies carried out with the complete model (see Appendices 1 and 2) and with the anonymised model (see § 8 of the agreement). Sections 2 and 4 to 10 apply to studies carried out with an equivalent (see § 7 of the agreement).

PROCEDURE FOR THE MAINTENANCE AND USE OF THE NORDEL DATA SET

This appendix described the procedure for the maintenance and use of the grid model and multi area power market simulator at the date of signing of the agreement.

A distinction is made between operational studies and planning studies.

Operational studies are carried out by the parties when necessary.

At the start of a planning study, if the result concerns more than two parties, the parties to the agreement are informed of the aims and timetable of the study not later than the first meeting of the Planning Committee of Nordel. The results of such a jointly carried-out planning study will be given to all parties to the agreement.

The chairman of the Planning Committee or the Operations Committee (as appropriate) must stress to any new members of the committees that everyone who is given access to the data must be aware of the content of the data exchange agreement.

Use of consultants
Each TSO chooses its own consultants.

The Nordic TSOs agree only to use consultants whose strategic interests are beyond question.

Any doubts must be raised with the TSO concerned before the data set is handed over.

Grid model data set
The grid model data set includes a data set for expansion planning to be used by, among others, the Grid Group, and a data set for operational planning, to be used by, among others, the Analysis Group of the Operations Committee.

Data sets must be established and supplied in the format for the latest version of a jointly chosen analysis software. At the signing of the agreement this is the analysis software PSS/E version 30 (from the company Siemens PTI).

A company is responsible for the functionality and updating of the Nordic dynamic grid model for a period of three years. The grid model must be a model for performing load-flow and dynamic analyses for the Nordic interconnected-operation power system. Since the major part of the model, namely the dynamic data, is common to operations and planning, the model is common to the Grid Group and the Analysis Group.

Svenska Kraftnät is responsible from 2005 to 2007 inclusive.

The parties to the data exchange agreement undertake to provide the best possible basis available for the work on the common grid model.

In addition to the necessary data it includes resources for making the multiarea power market simulator work and reflect the physical situation and to ensure that the content of the model is documented both technically and clearly.

Any revision of the grid model and the preconditions for a new model will be decided on by the Grid Group. The need for revision or for the creation of a new model is normally assessed yearly. In addition, all the parties to the agreement must provide information about important changes that may be significant for the multi area power market simulator, as quickly as possible.

Multi area power market simulator data set
The members of the Balance Group must regularly gather and maintain data on production systems, transmission systems and electricity consumption in the respective country, for the work of the group.

Data sets must be established and supplied in the format for the latest version of a jointly chosen analysis software. At the signing of the agreement this is the analysis softwares “Samkjøringsmodel” (*multi area power market simulator*) (from SINTEF of Norway) and “Samlastmodel” (multi area power market simulator) (from Powel of Norway).

Updating and filing procedure
The procedure is updated as necessary in accordance with § 3 of the agreement, and is approved by unanimous decision of the Planning Committee.

The chairman of the Planning Committee is responsible for ensuring that the currently valid procedure is filed at the Nordel secretariat.

Annex: GMS Grid Code

Madrid - Washington DC
Rio de Janeiro - Buenos Aires - Montevideo

STUDY FOR A REGIONAL POWER TRADE OPERATING AGREEMENT IN THE GREATER MEKONG SUB-REGION

TA 6100-REG

GRID AND SETTLEMENT CODE OF THE PTOA (PTOA-GSC)

Prepared for:

ASIAN DEVELOPMENT BANK

M 0720 P 083–02

August 2005

GRID AND SETTLEMENT CODE OF THE PTOA

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DEFINITIONS AND ACRONYMS

Article 1 The following definitions apply to this Grid and Settlement Code of the PTOA (PTOA-GSC)

Agent: a set of entities or companies at each Stage of the PTOA's development that are appointed/authorized by each Country to present offers-bids and/or to schedule physical transactions in the regional network. For Stages #1 and #2, the Agents are exclusively single buyers of each GMS country. During these Stages, each Member Country can entitle other companies to participate or schedule transactions in the national electricity systems or markets, but only the Agent of each country shall be able to present offers-bids.

Authorized Revenue (of a TFO): the compensation that a TFO is allowed to receive as compensation for costs incurred as a result of hosting Cross-border Load Flows of electricity on their transmission facilities that are part of the TNM, by Agents that schedule Cross-border Transactions.

Calculation Hours: the hours used for the calculation of the ITCC. These hours are 8:00, 14:00 and 20:00 of Working Days.

Control Points: a set of sub-stations or points of connections of Agents to the TNM where TSOs are responsible for maintaining the voltage levels within the upper and lower limits as specified in the Static Security Criteria defined in Title 3.6 of this GSC. These Control Points shall be identified by the Operational Planning Working Group and shall be monitored by the MSC.

Cross-border Load Flow: physical flow of electricity through an Interconnector that arises from energy trading among Member Countries. Cross-border Load Flows can be originated by trading between any pair of countries, not necessarily those located in extremes of the Interconnector. Cross-border Load Flows may arise also from the loop effect produced by load flows within one country.

Cross-border Trading: the set of transactions associated to energy trading among Member Countries.

Cross-border Transactions: each transaction that implies energy trading between Member Countries.

Dispatch Center (of the RTC): a division of the RTC that is responsible for preparing the Regional Economic Dispatch, metering the Cross-border Load Flows, preparing the settlement, and developing and maintaining the Regional Database.

Dispatch Interval: the time interval for which the Regional Economic Dispatch is performed. It is initially defined as an hour, and can be reduced by the RRB.

Emergency Operation State: the operation state that occurs whenever an unexpected event dictates that Cross-border Transactions scheduled for a particular time should be reduced or increased more than 20%, or changes are greater than 10% of the demand of the country that is importing energy.

Flexible PPA: a PPA which has a two-part price, and that both parties accept that it shall be dispatched by the RTC. The information for the dispatch of the PPA shall be presented by the respective TSO, as bids and offers.

Independent Power Producer: any generator different from the state-owned generation or integrated companies. Nevertheless government-owned generators or integrated companies may have some stake in an IPP.

Interconnector: a transmission line that crosses or spans a border between Member Countries and which connect the national transmission systems of both Member Countries. At each end of the Interconnector, there is a Control Area of the corresponding Member Country.

International PPA: a PPA in which the two parties are Agents or IPPs of different Member Countries.

Inter-TSO Compensation Charges: the compensations that result from the application of the Inter-TSO Compensation Mechanism.

Inter-TFO Compensation Mechanism: the compensation that the TFO of each country shall receive for the use of its network for hosting Cross-border Trading.

Mekong Electricity Trading Arrangements: the physical and legal framework where energy transactions among GMS countries are performed.

Member Countries: PDR of China; Kingdom of Cambodia; Lao PDR; Myanmar; Republic of Vietnam; Kingdom of Thailand

Monitoring and Supervision Center (of the RTC): the center owned and operated by the RTC that is responsible for monitoring the real-time operation of the TNM according to PTOA, and which coordinates the regional operation when the intervention of several TSOs become necessary.

Net Withdrawal (of energy of a country from the Trading Network Model): the sum of imports of a Country from other Member Countries, less the sum of its exports, through the TNM, for each Dispatch Interval. If this figure is negative, Net Withdrawal is zero for this Dispatch Interval. The exports and imports are measured indirectly at the point where each Inter-connector crosses the border of the Country.

Net Injection (of energy of a country into the TNM): the sum of exports of a Country to other Member Countries, less the sum of its imports, through the TNM, for each Dispatch Interval. If this figure is negative, Net Injection is zero for this Dispatch Interval. The exports and imports are measured at the point where each Inter-connector crosses the border of the Country.

Operations Planning Working Group: a Working Group of the RPTCC, which is responsible for performing operative studies of the TNM, and to identify the components of the TNM.

Opportunity Cross-Border Transaction: a transaction between GMS countries with duration of one Dispatch Interval, which is scheduled by the RTC as result of the Regional Economic Dispatch.

Penalty Factor: it is equal to 15% (fifteen percent). The RRB shall be able to change this value in order to improve the resulting Cross-border Trading performance.

Performance Standards: It is a set of parameters and operational criteria of the transmission system wherein pre-defined lower and upper limits (and criteria) must be respected in the operation and design of the transmission system.. The Performance Standards are presented in chapter 3 of the Grid Code.

Planned Outage: an outage of a transmission facility of the TNM equipment for maintenance or repairs, and that has been informed by the respective TSO a week in advance, or which was included in the outages coordinated schedule.

Power Trade Operating Agreement: the rules for regional energy trading, and the documents where those rules are written.

Power Purchase Agreement: a contract for selling/buying power, between an Agent of a Country and an IPP located in another Country, or between Agents of different Countries.

Regional Commercial Metering System: the system used to measure Cross-border Load Flows in the TNM.

Regional Database: the database that stores all of the information necessary for the Regional Economic Dispatch, the operational planning and the regional planning.

Regulatory Authorities: the regulatory authorities of the Member Countries, or the government's agencies that accomplishes the corresponding functions.

Regional Demand: the purchase of energy from an Agent, which results from an International PPA of from the opportunity economic dispatch.

Regional Economic Dispatch: the daily scheduling of Opportunity Cross-border Transactions, with the objective of minimizing the variable costs of GMS countries, once they schedule the cross-border PPAs.

Regional Transmission Network: is the set of all the Member Countries transmission networks that are necessary to represent for power system studies. In stage#4, it will coincide with the TNM. The Regional Transmission Network should be used to perform the expansion studies of the TNM and to perform power system studies in order to check on the security of the interconnected national power systems based on the Performance Standards, or other issues that can have an impact on the security of the interconnected national power systems

RRB Resolution: an administrative decision of the RRB, which is mandatory for the TFOs and Agents that participates of PTOA.

Scheduled Flows: the power load flows through the Interconnectors that arise from the Regional Economic Dispatch and the PPAs.

Single Buyer: each Electricity Utility entitled by each GMS country for exporting and importing energy from GMS countries. It also usually implies that this single entity has been granted the exclusive legal right to supply all of the power needs of the distribution entities (and eventually eligible large consumers). The common approach in the GMS region is to have the state-owned integrated power company purchasing part of the energy from independent power producers to supply its own distribution division.

Standard Unit Costs: a set of costs per km of line, MVA of transforming capacity or compensation devices, or of specific equipment such as switchyard, connection, protection, etc. These costs are deemed as representative of efficient construction or purchase, and shall be set by the RRB

System Planning Working Group: a Working Group of the RPTCC, which is responsible for performing medium- and long-planning studies of the TNM, and for recommending upgrades or construction of new transmission facilities that allow for the increase of the cross-border transmission capacity.

Trading Network Model: is the simplified physical net used to accept / reject the offers /bids for international trading and where the cross-border trading actually takes place. It is composed of all the elements used for cross-border exchanges, which will be used for the purpose of economic dispatch, pricing and settlement.

In relation with the Trading Network Model, the following conventions are used:

> **Expansion of the Trading Network Model** means an expansion of the Regional Transmission Network oriented to increment the cross border trading capacity
>
> **Studies of the Trading Network Model** means studies on the Regional Transmission Network oriented to analyze the performance of the Trading Network Model
>
> **References to installations or facilities of the Trading Network Model** are references to installations or facilities of the Regional Transmission Network that are part of the Trading Network Model, or that are represented as an equivalent component of the Trading Network Model.

Transit Load Flow: physical flow of electricity on transmission network of a TFO of a Member Country that results from the impact of the activity of Agents outside of that Member Country. Transit Load Flows result from cross-border energy exchanges where injections and/or loads are located outside of the country where the TFO is located. These Transit Load Flows shall be determined on the basis of the physical flows that are actually measured at the interconnections between each Member Country in a given period of time.

Transmission Facilities Owner: a company that owns transmission facilities that is part of the Trading Network Model. They may be the national utilities or other owners such as IPPs that build transmission facilities to connect their power plants with the network of the buyer of the energy that they produce.

Transmission System Operators: the national entities that retain full control and responsibility for the operation of national transmission networks under a regulated regime. In the future (Stage #3 onwards), these entities shall also be responsible in providing third-party access to the transmission users. TSOs have full responsibility for the national economic dispatch and balancing activities of the countries' transmission system and the provision of ancillary services to all system users within their countries. Economic dispatch shall observe security constraints. TSOs shall organize at the national level the basic supply of balancing services, and shall take into consideration the agreed Cross-border Trading. They shall collaborate with other countries' TSOs in the coordination of the MSC for Opportunity Cross-border Transactions and in the settlement of imbalances. They shall be fully responsible for the corresponding transactions at a national level. TSO may be also the owner of the Transmission Network of its country, but in this PTOA-GSC this function is separately regulated.

Unplanned outage: an outage of a Trading Network Model transmission facility that is not a Planned Outage.

Value of Lost Load: the social value of non served energy.

Working day: a weekday from Monday to Friday, excluding public holidays in some of the Countries.

Working Team for PTOA-GSC Reform: a transient structure dedicated to the treatment of specific reform proposals to the PTOA-GSC, integrated by personnel from both the RRB and the RTC, which eventually can include external specialists.

Article 2 The following acronyms are used in this PTOA-GSC:

AGC: Automatic Generation Control

GMS: Greater Mekong Sub-region

PTOA-GSC: Grid and Settlement Code of the PTOA

IPP: Independent Power Producer.

IGA: Inter-Governmental Agreement on Regional Power Trade in GMS

ITCC: Inter TFO Compensation Mechanism

MSC: Monitoring and Supervision Center (of the RTC)

OPWG: Operational Planning Working Group

PTOA: Power Trade Operating Agreement.

PPA: Power Purchase Agreement.

RCMS: Regional Commercial Metering System

RPTCC: Regional Power Trade Coordinating Committee

RRB: Regional Regulatory Board

RTC: Regional Transactions Coordinator

RTN: Regional Transmission Network

SPWG: System Planning Working Group

TFO: Transmission Facilities Owner

TNM: Trading Network Model

TSO: Transmission System Operator

VOLL: Value of Lost Load

WTGSC: Working Team for GSC Reform

PREAMBLE

The Governments of the Greater Mekong Sub – Region (hereafter referred to as GMS), namely: the Kingdom of Cambodia, the People's Republic of China, the Lao People's Democratic Republic, the Union of Myanmar, the Kingdom of Thailand, and the Socialist Republic of Viet Nam (hereafter referred to as the Country Members);

RECOGNIZING that the national power utilities of the GMS are engaged in the electricity supply business in their own countries and that the said utilities wish to continue with the development of interconnections between their respective networks and expand capacity and energy trade to provide further opportunities to: (i) enhance the reliability of supply, (ii) coordinate the installation and operation of generation and transmission facilities, (iii) reduce investment and operating costs, and (iv) share in other benefits resulting from the interconnected operations of their systems;

MINDFUL that GMS Member Countries, demonstrating their recognition of the benefits of cooperation amongst their national power sectors, formed the GMS Electric Power Forum (EPF) in 1995 and the Experts' Group on Power Interconnection and Trade (EGP) in 1998 to study and provide recommendations regarding power in the GMS, signed the Inter – Governmental Agreement on Regional Power Trade in the GMS (IGA) in 2002;

RECALLING, that the Regional Power Trade Coordinating Committee (RPTCC) established by the IGA has developed the steps to establish and implement regional trade arrangements, including: (i) a final draft of the Regional Power Trade Operating Agreement (PTOA) which specifies the rules of regional power trade, (ii) recommendations to the Country Members on the overall policy and day–to–day management of regional power trade, including the necessary bodies for coordination (iii) the establishment of short, medium and longer initiatives which need to be pursued on a priority basis in order to achieve the objectives of regional power trade within a specified timetable; and (iv) identification of necessary steps for implementation of regional trade, which where included in the Memorandum of Understanding signed by the Country Members Ministers.

RECOGNIZING the need to implement the institutions necessary to rule, conduct and supervise the regional power trade as established in the PTOA, namely the Focal Group, the Planning Working Groups, and when considered convenient the Regional Transactions Coordinator and the Regional Regulatory Board.

Now, through their duly authorized representatives who are the signatories of this Basic Agreements to Begin Trading in the GMS, the Parties agree that the following rules will regulate the regional power trading:

GENERAL CONDITIONS

1. OBJECTIVE OF THE GRID AND SETTLEMENT CODE OF THE PTOA (PTOA-GSC)

Article 3 The general objective of the Grid and Settlement Code of the PTOA (PTOA-GSC) is to establish the criteria, procedures, rules and guidelines related to the PTOA and Transmission Service in the TNM; which are applicable, to the RTC, the TSO of the Member Countries, the TFOs that own facilities allocated to the TNM and the Agents. This PTOA-GSC defines the rights and obligations of the parties, the rules for access and connection, the planning and expansion, the tariff regime, the Performance Standards, the quality of service targets of the TNM and the rules for Regional Economic Dispatch and settlement. These shall also follow the established criteria in the IGA.

Article 4 The specific objectives of the current PTOA-GSC include:

4(a) To establish the rights and obligations of the RTC, the TSO, the TFO and the Agents who schedule Cross-border Transactions and are users of the TNM, while also delineating between the responsibilities of the RTC and each TSO, and between a TSO and the Agents that use its network. To set the general principles that shall be used by the SPWG and the OPWG to carry out the studies that are under their responsibility.

4(b) To set the criteria to ensure that the Regional Transmission Service is done in transparent and equitable conditions for all the Agents, while also observing the performance and security criteria provided under this PTOA-GSC.

4(c) To establish the methodology for defining the transmission facilities that are part of the TNM and the RTN;

4(d) To establish the regulation at a regional level on the minimum requirements that should be fulfilled by an Agent before it can connect its new equipment to the RTN, whether it may affect the performance of the TNM;

4(e) To establish the technical and economic criteria for conducting studies on expansion planning of the RTN, in cases when it can augment the capacity of the TNM, the consequent investment plans, and the programs that shall be implemented to incorporate the new transmission facilities;

4(f) To establish the methodology for calculating the Authorized Revenues of the TFOs (amortization, return on investments and recovery of operation and maintenance expenses), and the methodology for calculating the ITCC that the Agents are obliged to pay;

4(g) To establish the rules for the economic Cross-border Trading between the Agents, through a pricing system for the energy traded and rules for the use of the TNM;

4(h) To define the Performance Standards for the TNM;

4(i) To establish the operation and design parameters of the RTN in cases that can augment the transmission capacity of the TNM that must be followed to guarantee the fulfillment of the Performance Standards;

4(j) To establish the criteria and scope of the service quality regime for the TFOs and the TNM.

4(k) To enable the RTC and TSO to prepare Regional Economic Dispatch, which consists of the schedule of Cross-border Transactions based on a maximum benefit dispatch model which, amongst other things, models bids and offers of the Agents. The procedures defined in this PTOA-GSC shall ensure:

1. That the Performance Standards are accomplished;
2. That all the parts involved provides the information necessary for the Regional Economic Dispatch
3. That the RTC shall use an appropriate methodology for the Regional Economic Dispatch
4. That the transactions are properly metered
5. That the RTC carry out the settlement of the Cross-border Transactions

2. SCOPE OF THE PTOA-GSC

2.1. PARTIES OF THE CODE

Article 5 The present PTOA-GSC shall be applied to all Transmission Services in the GMS through the TNM, including the related activities of the following institutions:

1. The RTC
2. The TSO of the Member Countries
3. The TFO whose facilities comprise the TNM
4. The Agents
5. Third parties authorized by the TSO of each country to perform Cross-border Transactions and interconnections of non-member countries in case this are developed

Article 6 The present PTOA-GSC is organized in five sections:

1. Definition and Acronyms
2. General Conditions
3. The Grid Code
4. The Settlement Code
5. Transitory Measures

The details of the terms, procedures, data, formats and other characteristics of the studies or methodologies that shall be used for the implementation of the present PTOA-GSC are presented in Annexes. The Annexes are part of the PTOA-GSC, with the same scope and validity, and are for the obligatory fulfillment of the Agents, the TFO and the RTC.

Article 7 It is the responsibility of the RRB to approve and, when necessary, to modify this PTOA-GSC and their Annexes. The Annexes shall have to be developed within the framework of the general principles, criteria and procedures that are established in this PTOA-GSC.

2.2. HIERARCHY OF DOCUMENTS

Article 8 The hierarchy that shall be followed in regulating the transmission services in the TNM is:

I. The IGA;
II. The Protocols between the Member Countries;
III. RPTCC Decisions
IV. This PTOA-GSC, and the Annexes;
V. RRB Resolutions;
VI. RTC documents that have been approved by the RRB;
VII. The Regulations of the Member Countries.

2.3. RRB FUNCTIONS

Article 9 The following functions and responsibilities are assigned to the RRB:

9(a) Approve the connection of new Agents who, under this PTOA-GSC, connect themselves to the TNM.

9(b) Approve modifications to this PTOA-GSC.

9(c) Approve the RTN expansions that may increase the transmission capacity of the TNM, which shall arise from the Regional Transmission Planning performed by the SPWG, and propose these expansions to the RPTCC.

9(d) Approve operative documents that the RTC must use, making them compatible with the national regulations.

9(e) Apply the fines or sanctions that could be levied to the Agents or TFOs.

9(f) Mediate disputes between the parties involved in the PTOA: RTC, TSOs, TFOs and Agents.

3. CHANGES TO PTOA-GSC

3.1. INTERPRETATION OF THE REGULATION

Article 10 Interpretations that RRB makes on the description and scope of the present PTOA-GSC shall be formulated through Resolutions. The interpretations must be made and presented while ensuring the fulfillment of the established objectives in the IGA and PTOA-GSC.

Article 11 The RRB may to give to its interpretations the character of ‘modification of the PTOA-GSC’.

Article 12 The names of the Chapters (identified by one digit), Titles (identified by two digits) and Sub-titles (identified by three digits) of this PTOA-GSC have only informative purposes and they are not subject to be used for the interpretation of this PTOA-GSC.

Article 13 The references to dates must be interpreted such that it is the date indicated, or the following first working day as prescribed in the RTC.

Article 14 The concepts defined in section “Definitions and acronyms” or throughout this PTOA-GSC, when they appear in capital letters must be interpreted with the meaning given in the definition.

3.2. FULFILLMENT OF THE RULES AND SANCTIONS

Article 15 The RRB has the power to impose the fines and sanctions establish by this PTOA-GSC.

3.3. CAUSES FOR CONSIDERING PTOA-GSC MODIFICATIONS

Article 16 The PTOA-GSC can be adapted to the changes that arise within the PTOA, in order to incorporate modifications such as upgrades in the required quality of service, new alternatives to facilitate the expansion of the system and measures to obtain greater efficiency in their execution and to the technological changes that take place. In the formulation and approval of such modifications to the Regulation, the RRB shall take into consideration the Principles and Objectives of Power Trade in the GMS, as it is established in Article 2 of the IGA.

Article 17 The present PTOA-GSC and their Annexes can be modified on the basis of proposals properly justified by at least one of the following reasons:

17(a) Situations that affect the TNM but were not anticipated in the present PTOA-GSC and its Annexes.

17(b) Change of stages of the PTOA

17(c) The experience in the application of this PTOA-GSC and its Annexes demonstrates that i) it is possible to introduce changes that significantly improve the benefits of the regulatory objectives, or ii) it is necessary to eliminate elements that are opposite to the objectives of the IGA.

3.4. EVALUATION OF THE PERFORMANCE OF THE RT

Article 18 Every year the RRB shall evaluate the performance of this PTOA-GSC and its annexes in order to maximize the operating efficiency, the efficient expansion and the security and reliability of the TNM.

Article 19 Before October 30th of each year, the following reports shall be submitted to the RRB by the corresponding institutions identified below. These reports shall include an analysis of the application of this PTOA-GSC up to that date.

19(a) Report from the RTC on the results and implementation /application problems of the PTOA-GSC. These reports must specifically address the problems referred to the efficient administration of the quality of SER; efficiency, reliability and coordination of the operation; network constraints and their impact in operation and supply; and transparent administration of the open access for new demands or supplies. The RTC may present proposals of modifications based on its knowledge and experience in the administration of the system, the situations that were verified during the implementation of the rules and their consequences in the system' operation.

19(b) Reports from the TSOs on the coordination of the operation of their grids and information exchanges; conflicts due to the open access; and any other problem or conflict that may have arisen due to the application or interpretation of this PTOA-GSC. The report may present proposals for modifications based on their experience and knowledge of the TNM and RTN under their responsibility and the activity of the Transmission Service and its quality obligations.

19(c) Proposals to modify the rules presented by the Agents. Each proposal shall contain its justification and shall include at least a valuation of its impact in the forecasted quality of the Transmission Service, on the improvement in the economic transactions in the region and on the future requirements of new connections and expansions.

Article 20 The RRB shall evaluate the proposals for modifications. Whenever it considers that one or more presented proposals are valid, it shall organize a Working Team for PTOA-GSC Reform (WTGSC) that shall have as objective to evaluate and develop a proposal or a group of proposals for PTOA-GSC modification. The WTGSC is a transient structure integrated by personnel from both the RRB and the RTC, which eventually can include external specialists, dedicated to the treatment of specific reform proposals to the PTOA-GSC.

3.5. DEVELOPMENT OF THE MODIFICATIONS

Article 21 The WTGSC shall perform the following tasks:

21(a) Evaluate if there are enough reasons and valid circumstances that justify the proposed modifications.

21(b) Present to the RRB a preliminary report with its opinion on whether the proposed modifications are justified or not. If proposals are justified, the WTGSC shall include in the report its opinion on the proposed modifications.

21(c) Send the preliminary report to the TSOs and the RTC to have their opinion, comments and observations.

21(d) If the RRB considers that the modification is necessary, it shall produce a final report detailing the final version of the modification to the PTOA-GSC. This report shall describe the modifications suggested and their justification. The Final Report shall include the original proposals analyzed, and the comments and observations received on the preliminary report, indicating which suggestions were not accepted and why.

21(e) Present the final report to modify the PTOA-GSC to the RRB and a copy of this report to the RTC and the TSOs.

21(f) The RRB, when creating the WTGSC, shall establish the schedule for presentation of the preliminary report as well as for the consultations and the submission of the final report.

Article 22 After analyzing the final report for modifying the PTOA-GSC issued by the WTGSC, the RRB shall make a decision on approving the proposed modification or not. If the proposal is not approved, the RRB shall report its own evaluation on the final report issued by the WTGSC and a description of the reasons why the proposal was rejected. The RRB can approve the proposal submitted by the WTSGC with or without changes. In case that changes such as modifications or amendments are introduced, the RRB shall report the reasons that support such changes.

Article 23 Based on the final report, the adjustments and amendments decided by the RRB and the observations received by representatives of the Member Countries or third parties, the RRB shall approve the new version of the PTOA-GSC. The new PTOA-GSC is enforced once the RRB approves and publishes the modifications. .

Article 24 Whenever the RRB considers that a modification to the PTOA-GSC is needed so urgent that the established procedure cannot be followed, it shall proceed to make a temporary modification until the procedure can be fulfilled completely. The whole procedure shall be formally accomplished in all cases no later than six months after the temporary modification was enforced.

4. RESOLUTION OF DISPUTES

4.1. GENERAL PROCEDURE

Article 25 Those disputes that may arise between two or more Parties during the implementation of the PTOA and that cannot be solved in a first instance shall be treated according to the following procedure:

I. The disputing parties shall appoint representatives for purposes of formalized but amicable discussions regarding how such disputes may be resolved though compromise;

II. If the dispute involves a highly technical matter and resolution is unable to be reached through amicable discussions between the parties, the opinion of an independent ‘expert’ agreed by the parties will be taken into account;

III. If no amicable resolution is reached, an international arbitration tribunal will resolve the dispute.

Article 26 The arbitration tribunal shall be integrated by one member appointed by each one of the parties and a last arbitrator that shall be elected by the already appointed members. The last arbitrator shall serve as chairman of the tribunal. In case the tribunal thus integrated results in an even number of members, it shall agree on selecting an additional arbitrator.

Article 27 The rules and procedures for the international arbitration shall be those established by the International Chamber of Commerce (ICC).

Article 28 The venue for arbitration shall be in a neutral country and established by the tribunal once its members have been appointed.

Article 29 The arbitration process shall be conducted in English.

Article 30 The decisions of the arbitration tribunal shall be final and binding, and the Parties shall waive their right to appeal arbitration decisions to the courts.

Article 31 The role of the National Judicial Systems shall be that of enforcing the arbitration award and not to review the substance of the arbitration award. If corresponds, the institutions of the RPTCC (RRB, RTC) shall be in charge of enforcing the arbitration award.

4.2. RESOLUTION OF CONFLICTS BETWEEN GOVERNMENTS AND AGENTS

Article 32 The RRB shall issue a Resolution establishing the procedure to resolve the conflicts that may arise from the application of this PTOA-GSC as it is provided in Article 6 of the IGA.

Article 33 The RRB shall establish the procedure for the resolution of conflicts related to the interpretation of this PTOA-GSC.

4.3. DISPUTES ON SETTLEMENT

Article 34 Up to sixty (60) days after receipt of a Final Settlement Document, an Agent shall notify the RTC if the Agent disputes the Final Settlement Document concerning either:

34(a) The settlement amount stated in; or

34(b) The supporting data.

The RTC and the Agent shall use reasonable endeavors to resolve the dispute within fifteen (15) Working Days. If the RTC and the Agent do not reach an agreement, the RRB shall solve the dispute and its final decision on this matter cannot be appealed.

Article 35 If the Agent and the RTC reach an agreement or the dispute is resolved through the dispute resolution mechanism in any way which causes the settlement amount to differ from the settlement amount in the Final Settlement Document that caused the dispute, the RTC shall include the correction in the settlement amount and Settlement Document of the month when the dispute was solved or the agreement made.

The adjustment made to the settlement amount shall include the interests for the period from the payment date applicable to the disputed Final Settlement Document until the payment date of the Final Settlement Document that includes the correction.

Article 36 If within sixty (60) days of sending a Final Settlement Document, the RTC becomes aware of an error in a settlement amount in a Final Settlement Document, the RTC shall notify the affected Agents and include the settlement amount corrections in the Settlement Document of the month when the error was identified.

THE GRID CODE

1. THE TRADING NETWORK MODEL

1.1. TNM FACILITIES

Article 37 The Trading Network Model is the physical network where the cross-border trading actually takes place, and it is composed of all the elements used for international exchanges, which will be used for the purpose of economic dispatch, pricing and settlement.

The TNM shall represent fairly, and in a manner that will facilitate consistent and reliable operation of the power system:

I. The transmission network used by the RTC for cross-border trading,

II. Such other aspects of the power system which, when connected, may be capable of materially affecting Regional Economic Dispatch, the scheduled generating units or pricing of cross- border transactions.

III. The TMD model may contain such simplifications, approximations, equivalencies or adaptations as may facilitate the dispatch, pricing, or settlement processes.

Article 38 The SPWG, in coordination with the RTC, shall be responsible for identifying and updating the TNM.

Article 39 The SPWG shall perform all the periodic tasks necessary to identify the TNM components. Where appropriate, the RTC or the SPWG may recommend alterations to the market network model, so as to maintain:

I. The relationship between the TNM and the transmission network; and

II. Consistency with cross border trading requirements,

Article 40 The TNM shall include all the transmission lines that link Member Countries, the part of the interconnections with Non-Member Countries that are located within Member Countries, the planned expansions, and all of the elements belonging to each country that are essential for Cross-border Trading.

Article 41 The TNM definition shall be used to:

I. Specify the nodes where bids and offers for Opportunity Cross-border Transactions can be presented by the TSOs.

II. Specify the nodes where both injections and withdrawals associated to regional PPAs take place.

III. Define the minimal set of installations that shall be monitored by the RTC.

IV. Acknowledge and reckon the ITSC.

1.2. METHODOLOGY FOR IDENTIFICATION OF TNM INSTALLATIONS

Article 42 The methodology to define the TNM shall follow five steps, which are detailed in Annex 1. These steps are the following:

I. Definition of the basic TNM through the Interconnectors, National Country Networks, links with other Non-Member Countries and TNM expansions.

II. Identification of control nodes, which are those where the TSO are able to present bids –and offers for Cross-border Transactions.

III. Topological link of the elements identified at (I) and (II) through lines and other transmission elements.

IV. Identifications of other lines that, due to utilization criteria, should be included in the TNM.

V. The RTC in coordination with nationals TSOs may add other elements to those identified through steps I to V if they are based on regional operative security studies that show they are necessary to support established regional quality and security standards.

Article 43 To identify the TNM in a given year “t”, a three-year horizon shall be adopted, based on actual power load flows in the previous years. One element shall be a part of the TNM when its need is proved in accordance with established criteria in at least one of the horizon years.

Article 44 Whenever the RTC determines that a topological change in the regional network has a significant impact in the current TNM, it can redefine the TNM within a year.

Article 45 Prior to real operation, the RTC shall define the initial TNM, using the methodology described in Article 42 , based on simulations of the expected Cross-border Trading.

1.3. TNM PREPARATION

Article 46 The TSOs shall prepare models of their national transmission networks. These models shall be submitted to the RTC. These models shall represent properly the transmission constraints that may limit Cross-border Trading. Daily, each TSO shall inform the RTC on the available capacity at each link included in its model.

Article 47 The RTC shall prepare a TNM model based on the national networks models formulated by the TSOs, and its own information on capacity and constraints of each

Interconnector. This model shall be used for performing the Regional Economical Dispatch.

Article 48 The Operational Planning Working Group shall validate the TNM model, in order to ensure that it constitutes an appropriate representation of the transmission constraints that may limit the Cross-border Trading.

2. REGIONAL DATABASE

2.1. DEVELOPMENT AND MAINTENANCE OF THE REGIONAL DATABASE

Article 49 The RTC shall develop, maintain and administer a Regional Database structured on the basis of an integrated data model. The Regional Database shall contain all of the information necessary for the fulfillment of its functions, as well as the functions of the OPWG and SPWG. The Regional Database shall store the results of the daily Cross-border Transactions, events and emergencies; technical data of the TNM and the generation facilities connected to it; and on the evolution of the TNM and the Cross-border Trading.

Article 50 Agents, TSOs and TFOs shall have open access to the Regional Database

Article 51 The Regional Database shall contain all that information defined in this PTOA-GSC, and other additional data that the RTC may require in order to perform their functions and to fulfill their responsibilities.

Article 52 The Regional Database shall include all physical and economical information on Cross-border Trading; operative data and all the data necessary for the administration of the PTOA and the planned and coordinated operation of the TNM in accordance with the established parameters in this PTOA-GSC. The structure of the Regional Database shall be appropriate for storage, processing, registration and interchange of the information necessary for the development of the following processes:

I. Regional Economic Dispatch

II. Real-Time Operation

III. Metering

IV. Reconciliation, Invoicing and Liquidation of Transactions

V. Operating Plans and Operating Security

VI. Operational Planning

VII. Regional Planning

VIII. Supervision and Monitoring of the TNM

Article 53 A copy of the PTOA-GSC and other regulatory information on a regional level shall be stored in the Regional Database.

Article 54 The Regional Database shall be updated with information produced by the RTC and by information provided by the TSOs and the Agents, which shall be able to make the updates in automatic form from their own databases. The terms for the update of the information of the Regional Database shall be the defined by the RTC.

Article 55 The RTC, after consulting the TSOs, shall define the communication procedures for information exchange with the TSOs. The RTC shall specify the type, format and terms in which the information is provided. Periodically, and after consulting with the TSOs, the RTC shall be allowed to review and modify the communication procedures.

Article 56 The RTC shall define the procedures for the revision of the information provided by the TSOs for the Regional Database, including the criteria for rejection of information deemed as not reliable. These procedures shall define the consistency criteria for each type of information. In any case, the TSOs shall be responsible for the information that they provide.

Article 57 The RTC shall maintain as part of the Regional Database the information on the Regional Regulation, including the IGA and other Inter-Governmental Agreements, the PTOA-GSC and the Resolutions issued by the RRB.

Article 58 The Regional Database shall contain the parameters of the transmission systems, generating units and demand, as well all necessary information for the accomplishment of the studies of operative security, operative planning, the Regional Economic Dispatch, the evaluation of the events in the RTN that affect the Cross border trading or the TNM definition, the availability of the RTN affecting the TNM and the results of studies of simulation of the TNM which were carried out by the OPWG, the SPWG or the TSOs.

Article 59 The technical information stored in the Regional Database shall be maintained by the RTC for a minimum of five (5) years.

Article 60 The Regional Database shall contain at least the following data groups:

I. Group 1, Technical and engineering data of the generators that are in locations such that it must be included in the electrical studies of the TNM: data or parameters of the generation facilities (turbines, governors, exciters, impedances, synchronous control systems of generation, compensators, etc.).

II. Group 2, Data on operation of the generators: parameters to starting-up and operative shutdown of generating units, minimum stable generation and other restrictions.

III. Group 3, Data of the transmission facilities that are part of the TNM: electrical parameters of the lines or equivalents, transformers, switchyard equipment, compensation devices: impedances, reactance, ground impedance.

IV. Group 4, Profiles of demand, information on energy consumption, projections and characteristic of the load, in each withdrawal and/or injection node.

V. Auxiliary Group 5, Services: availability of auxiliary services, parameters and restrictions.

VI. Group 6, Maintenance Plans: maintenance plans of the transmission facilities and generation or large generation units that may affect the functioning or capacity of the TNM.

VII. Group 7, Information for the analyses of operative security and the operative planning: all of the additional information necessary to carry out the analyses of operative security and the operative planning that are requested in this PTOA-GSC.

VIII. Group 8, Report of events and faults of the TNM and the RTN that may affect the TNM.

IX. Group 9, Data of the Agents: additional information to carry out the Regional Economic Dispatch.

X. Regional Group 10, Information and studies: All the information and regional studies elaborated by the OPWG, SPWG, TSOs, RTC and other organisms.

XI. Group 11, Information of the interconnections with countries that are not members of the GMS: electrical parameters and other information on the inter-connectors that are required for the planning studies and operative security.

2.2. REQUIREMENTS TO BE FULFILLED BY THE TSO

Article 61 The TSOs shall fulfill the following activities in relation with the Regional Database:

I. To organize and to maintain national databases, with the characteristics of the national transmission system, topology of the network, characteristics and electrical parameters of generators, profiles of demand by node, projections and characteristics of the load and levels of generation by node, with open access to the RTC.

II. To organize a national database with the operation records of the system that it supervises,

III. To organize a national database with the operative and expansion studies of the system that it supervises, with open access to the RTC.

IV. To incorporate in the national database the information that originated from the real time operation of the TNM.

V. Each TSO shall be in charge of updating the Regional Database with the information that originated from its country.

The RTC shall have open access to the information of the national databases that are associated to the TNM and Cross-border Trading.

2.3. REQUIREMENTS TO BE FULFILLED BY THE RTC

Article 62 The RTC shall fulfill the following activities in relation to the Regional Database:

I. To centralize the information exchange between the TSOs, the TFOs and the Agents.

II. To organize and administer the Regional Database, granting open access to the TSOs, the TFOs and the Agents.

III. To make available to each TSO the results of the dispatch and real-time operation of the TNM, as well as other operative information on Cross-border Trading.

IV. To review and approve the information provided by the TSO.

V. To maintain updated the information of the Regional Database.

VI. To define the formats for the provision of the information for the Regional base of data. The RTC shall inform the TSOs with fifteen (15) days' notice on any modification to these formats.

2.4. DATA UPDATE

Article 63 Each TSO shall update each six months the information it is obliged to submit for the Regional Database. Deadlines for data submission shall be May 15th and November 15th of each year, or when a significant change in the configuration of its system occurs. Specific information shall be updated according to the specifications defined in this PTOA-GSC. If a TSO does not update this information, the RTC is able to use the most recent information available and shall inform the RRB on the use of such data.

Article 64 The information on parameters and initial data could be formulated and sent by letter, fax or electronically. Some operational information could be interchanged via voice and electronic means. Data on events, records on faults and sequence of events could also be interchanged through electronic means. The operational data shall be exchanged in real time through adequate channels and automatic devices.

Article 65 In any case, the RTC shall define the form and means by which the information in the regional database is updated. The RTC shall inform the TSO on the data that require to be updated in real time and/or in automatic form; for which the respective TSO shall present for RTC approval a program of activities to accomplish this requirement.

3. TRANSMISSION STANDARDS

3.1. SCOPE OF TRANSMISSION STANDARDS

Article 66 The Transmission standards shall consist of Design and Performance Standards.

3.2. THE DESIGN STANDARDS

Article 67 All the equipments to be installed in the RTN, that may affect the performance or capacity of the TNM, including the connection assets, shall fulfill the following general design standards. The order of the following list gives the fulfillment priority. :

1. The design rules set herein;

2. The International Electro-technical Commission (IEC) standards;
3. RRB-approved practices or standards in the countries.

Article 68 All equipments to be connected to the RTN that may affect TNM performance or capacity shall fulfill the following criteria:

68(a) It must allow the TNM to operate in accordance to the Performance Standards that have been defined in this Chapter;

68(b) It must withstand current or future fault levels, based on the natural evolution of the TNM;

68(c) The higher voltage windings of transformers must have its neutral connected to earth;

68(d) It must withstand, without damage, over-voltages caused by switching transients or induced by lightning;

68(e) It must fulfill the environmental requirements;

68(f) It must meet the maximum fault clearance time that has determined by the Operational Planning Working Group prior to the design of the connection;

68(g) Each TSO shall be responsible of ensuring that the Agents and/or its country system are integrated into a Supplementary Control System (SCS) that shall be designed to preserve the security of the system. The Operational Planning Working Group, in consultation with the RTC and the TSO, shall define the SCS specifications. Primary objective of the SCS is to prevent perturbations in a country's network being extended to other countries' networks.

68(h) The TSO shall be responsible of ensuring that new generation facilities wishing to connect directly or indirectly to the TNM must fulfill the following characteristics:

I. It must have Black Start capability for units rated higher than 100 MW;

II. It must have Real and Reactive Power Supply capability during extreme voltage and frequency deviations as established in the Performance Standards, thereby allowing the control of voltage levels in the Control Points;

III. It must be able to automatically control their reactive power output within their reactive capabilities through an excitation control system;

IV. It must be able to stabilize power oscillations that may affect the TNM through power system stabilizers for synchronous generators rated higher than 50 MW;

V. It must be able to respond to control requirements under expected normal and abnormal conditions;

VI. It must be able to perform automatic disconnection when necessary to prevent any damage to the generating unit or any threat to the TNM;

VII. For design purposes, the Generator must consider that the system frequency could rise to 53.0 Hz or fall to 47.00 Hz. The unit must withstand these extreme values for a period of at least 10 seconds. These limits must be confirmed or modified by studies performed by the Operation Planning Working Group.

Article 69 The equipment to be installed in the RTN that may affect TNM performance or capacity, including those of the connection points, shall fulfill the norms of the country where the new equipment will be installed at least for those aspects covered by this PTOA-GSC. In all cases, the equipment shall allow the operation of the TNM according to the Performance Standards, and complying with the Documents that the RTC releases on the subject.

Article 70 If there are differences between the norms and/or criteria used in each country that make reconciliation necessary or advisable, the TFO shall submit to the RRB a request containing a technical analysis of the disagreement, its effects on the TNM and the proposal for modification.

Article 71 After the request provided in Article 70 is received, the RRB in coordination with the RPTCC shall consult with the responsible agencies in the affected country. The RRB shall evaluate the findings and make a proposal for new regulation applicable for the whole jurisdiction of TNM if considers this advisable

3.3. THE TRANSMISSION DESIGN CODE

Article 72 The RRB shall develop or select the Transmission Design Code based on the standards that are being used in the region or in other parts of the world. This Code shall establish the technical design characteristics and procedures for designing the transmission facilities that will be part of the RTN that may affect TNM performance or capacity. This Code shall have technical requirements that are no less strict than those currently being used by the Member Countries.

Article 73 The Transmission Design Code shall establish the design and operation standards that enable the development of an efficient and reliable TNM, and should be fully consistent with the technical and operational reliability and service quality requirements that have been established in this PTOA-GSC.

Article 74 The Transmission Design Code shall cover the technical, design and operational criteria and procedures that must be followed by any TFO or Agent that is connected or applying for connection to the TNM. This includes:

I. Design of lines and substations;

II. Grounding requirements for overhead lines and substations;

III. Protection and control design; and

IV. Right-of-ways for electric lines.

Article 75 The Transmission Design Code shall include:

75(a) Connection provisions that specify the technical and design criteria;

75(b) The technical and design criteria of TNM facilities that must be taken into account by the TFOs and Agents that are connected to or applying for connection in planning and designing their equipment to be connected;

75(c) The technical design and operational requirements that are needed to protect the security and quality of service of the TNM under both normal and abnormal/emergency situations.

Article 76 Upon the issuance of the Transmission Design Code by the RRB, the TFOs shall implement the necessary measures to comply with the Transmission Design Code for their respective transmission facilities that are part of the TNM.

Article 77 The Transmission Design Code shall be compatible with the corresponding regulation of the Member Countries. The RRB shall be responsible in coordinating with the authorities of each Country in resolving potential conflicts that may emanate from the use of the Transmission Design Code. The RRB may introduce the necessary amendments. However, these amendments should not result to changes of the Performance Standards of the TNM.

Article 78 The TFOs shall design in accordance with the Transmission Design Code any expansion or upgrade of their transmission facilities that are part of the TNM.

Article 79 The RRB shall periodically or upon request by the RPTCC, review the Transmission Design Code and its implementation. This review shall include a consultation process with the TSOs, RTC, Agents and TFOs.

3.4. THE PERFORMANCE STANDARDS

3.4.1. GENERAL CONDITIONS

Article 80 The Performance Standards on reliability and quality of service that are defined in this title shall be followed in the design and operation of the components of the RTN that may affect TNM performance or capacity. The TSOs shall take these into account in operating their respective national networks to enable the TNM to meet the set Performance Standards.

Article 81 The Performance Standards defined in this title shall be used for:

81(a) TNM expansion planning, by the Planning Working Groups and the National TFOs;

81(b) Operational Planning, to be performed by the respective Working Groups—the National TSOs to handle the national dispatch and scheduling of cross-border PPAs, while the RTC shall be responsible for the Economic Regional Dispatch of opportunity transactions; and,

81(c) Decisions in real-time operation and dispatch-instructions that shall be made by the countries' TSOs or by the MSC of the RTC.

Article 82 The Performance Standards are defined in the following titles of this PTOA-GSC according the following detail:

I. Static security, under Title 3.6.

II. Dynamic security, under Title 3.7.

III. Generating plants Black Start requirements, under Title 3.10.

IV. Minimum requirements for frequency regulation and control of interchange in the inter-connectors, under Title 3.7.

V. Assignment of responsibility for operational reserves, under Title 3.8.

VI. Measures for voltage control, under Title 3.9.

VII. System restoration after blackouts, under Title 3.10.

Article 83 The studies for the modification of parameters and criteria of Performance Standards shall be carried out by the Operational Planning Working Group in consultation with the RTC and the TSOs.

3.5. REVISION AND MODIFICATION OF THE PERFORMANCE STANDARDS

Article 84 The Operational Planning Working Group shall monitor and inform the Agents, the RTC, the TSOs and RRB on the operative results and costs of the established Performance Standards.

Article 85 The RRC is able to order for a revision of the Performance Standards to comply with technical or security regulations.

Article 86 The Operational Planning Working Group, in consultation with the RTC and the TSOs, may propose and agree revisions and changes to the Performance Standards due to:

I. Problems detected during actual system operation;

II. Results of power system studies;

III. Analysis of events and disturbances in the systems;

IV. Technical and security standards set by RRB;

V. Defined requirement of ancillary services and dispatch to comply with the Performance Standards; and

VI. The risks associated with the performance parameters.

Article 87 The Operational Planning Working Group shall update these standards whenever Performance Standards revisions and modifications have been agreed upon by the RTC and TSO.

3.6. STATIC SECURITY CRITERIA

Article 88 The TSO shall be responsible in maintaining the established voltage levels within the capabilities of the existing equipment.

Article 89 The static security criteria are initially the following:

I. Operating voltage range of 0.93 to 1.07 per unit in steady state normal conditions (for nominal voltages used in GMS, namely: 500 kV, 220 kV and 132 kV).

II. Operating voltage range of 0.90 to 1.10 per unit after any single contingency.

III. Operating voltage range of 0.85 to 1.20 per unit after any multiple contingencies.

IV. Agents shall comply with lagging power factors of 1.0 or less during periods of low demand and 0.95 or higher during peak and shoulder hours.

V. Generators must deliver reactive power within their reactive power capabilities.

VI. The TFO shall be responsible for the compliance with the established voltage levels.

3.7. DYNAMIC SECURITY CRITERIA

Article 90 The dynamic security criteria are defined to ensure the system will remain stable under normal conditions following a single contingency. Automatic generation disconnection shall be allowed, provided it is not necessary to shed load.

As a general rule, the TNM shall be capable of withstanding and be secured against the following contingency outages without necessitating load shedding during steady state operation:

I. Outage of lines with voltage above 100 kV or,

II. Single phase to ground short circuit, with and without successful re-closing, in any line or substation bus with voltage above 100 kV, or in connections buses of generators with capacity above 50MW.

III. 3- phase short circuit in any line or substation bus with voltage above 100 kV, or in connections buses of generators with capacity above 50MW

The above contingencies shall be considered assuming pre-contingency system depletion with all the lines and substations in service, and the generating units may operate within their reactive capability curves and the network voltage profile shall also be maintained within voltage limits specified

Article 91 The frequency control criteria are as follows:

I. The equipment shall be designed for 50 Hz as nominal frequency of the electric system, allowing control within the boundary set by +/-0,2 Hz under normal conditions and toleration of transitory frequency variations of at least +3/-2 Hz.

II. The nominal frequency of the system and all equipment shall be 50 Hz and shall be controlled within the limits of +/- 0.2 Hz under normal conditions. Electrical equipment should withstand frequency transients of at least +3/-2 Hz.

III. It is not allowed load shedding after single contingency.

IV. Frequency may be controlled using primary or secondary frequency controls.

V. The national TSO, with the coordination of the Operational Planning Working Group, shall evaluate and monitor the behavior of the primary frequency control to identify and notify any related problem.

VI. Generating units, when synchronized to the TNM, shall operate continuously under the control of a governor control system, unless otherwise specified by the respective TSOs. The governor characteristics should be set within the appropriate ranges.

VII. No time delays other than those necessarily inherent in the design of the governor control system shall be introduced.

VIII. No frequency dead bands shall be applied to the operation of governor control system.

IX. The secondary frequency control shall be assigned by each TSO and shall be provided by the generators that have installed the required equipments for this purpose.

Article 92 The RRB can modify these parameters based on studies to be performed by the Operational Planning Working Group in consultation with the RTC.

3.8. OPERATING RESERVES

Article 93 The TSOs shall plan, dispatch and operate their respective systems while assigning sufficient operating reserves. They should consider factors such as uncertainties, generation and transmission equipment unavailability, number and size of generating units, system equipment forced outage rates, maintenance schedules, and regulating requirements, to ensure that their systems operate following the set Performance Standards. Each TSO shall take appropriate steps to protect the system against any contingency, following the loss of a generation resource or load connection.

Article 94 Each TSO shall determine the quantity of each required operating reserves necessary to ensure the accomplishment of the Performance Standards, while following economic considerations.

Article 95 The following relevant factors should also be considered:

95(a) Particular events of national or regional significance that may justify the provision of additional operating reserves;

95(b) The cost of providing operating reserves at any point;

95(c) The size and number of the largest generating units that are connected to the national grids, including exchanges in the Inter-connectors;

95(d) Weather conditions, insofar as they may affect (directly or indirectly) the generating units and/or the reliability of the national grids;

95(e) Historical availability and reliability performance of generating units and transmission lines;

95(f) Load forecasting uncertainties.

Article 96 In normal operating conditions and when sufficient reserves exist, each TSO shall maintain an operating reserve not less than 10% of the system's expected load. At least 50% of the operating reserves should be spinning while the rest shall be fast-start cold reserve, if available. The RRB can modify these parameters, based on studies to be done by the Operational Planning Working Group.

3.9. VOLTAGE CONTROL AND REACTIVE POWER

Article 97 The TSOs shall be responsible for:

97(a) Maintaining appropriate voltage control resources in the national networks to ensure voltage stability in the sub-stations that are connected to the Inter-connectors and which are necessary in controlling the Scheduled Flows;

97(b) Maintaining the voltages that have been specified in the Static Security Criteria at the Control Points that have been identified by the Operational Planning Working Group.

Article 98 The TSO shall use the following mechanisms for voltage control:

98(a) Transformer tap changing, cable switching, reactor and capacitor switching, and other control methods which only involve utilization of national resources;

98(b) Tap changing on generator transformers;

98(c) Demand power factor correction;

98(d) Scheduling must-run generation

98(e) Using generating unit reactive power, both by means of AVR control and through instructions from the TSO to adjust the reactive power output;

98(f) Switching of transmission lines.

Article 99 Each generating unit shall normally be operated under the control of a continuously acting AVR, which shall be set so as to maintain a constant terminal voltage. The AVR should also be set to stabilize power oscillations when equipped with power system stabilizers

Article 100 If for any reason a TSO is not able to maintain the voltage levels in the Control Points in the levels that have been specified in the Static Security Criteria, they shall inform to the MSC of the RTC, which shall then handle the coordination.

3.10. BLACK START

Article 101 Each TSO shall be responsible for re-starting its respective national transmission systems after a Black Out or severe contingency that disconnects its system from the TNM. Each TSO shall be responsible for ensuring generation units with Black Start capability are available.

Article 102 Appropriate tests shall be done on a periodic basis to ensure that the TNM can be restored following an extreme emergency or the total or partial Black Out of the system.

Article 103 The power plant that has been instructed to Black Start shall inform the TSO if, during the demand restoration process, any Black Start unit cannot support the demand requirements within its safe operating parameters.

Article 104 Whenever possible the TSO of countries affected by a Black Out shall coordinate the re-starting process. If they consider as necessary to re-configure the TNM or disconnect some Interconnectors, they shall ask the MSC of the RTC to coordinate the operation with all other TSOs that may be affected by the action.

4. METERING AND TELECOMMUNICATIONS

4.1. SCOPE

Article 105 The metering and telecommunication for the TNM and Cross-border Trading administration shall meet the requirements established herein.

4.2. INSTALLATIONS FOR METERING

Article 106 The metering, registration and acquisition of data system, which constitutes the RCMS, shall have three components:

106(a) The metering system of active and reactive energy in each node, including current transformers, voltage transformers and the energy meters.

106(b) An integrated system of registration and transmission of data, including registration equipment that can integrate and store the values of energy measurements from the meters.

106(c) A communications system for the remote access and collection of information by the MSC of the RTC.

Article 107 The energy flows through each Interconnector shall be metered using energy meters, which must be compliant with at least the following standards:

107(a) Accuracy class of at least 0.5;

107(b) Accumulation and storage of metered data with an integration period of 15 minutes;

107(c) Ability to allow remote data collection; and

107(d) Enough memory capacity to store registered information for at least 35 days.

Article 108 The accuracy class requirements of the energy meters and instrument transformers at each connection point shall be in accordance with the size of the load and shall meet the prevailing metering standards.

Article 109 The RTC may revise the metering standards. Modification of such standards shall require the approval of the RRB and an update of this Chapter.

Article 110 All the meters that are required at Inter-connectors shall be installed by the

TFOs of the Member Countries.

Article 111 The RTC shall ensure that the metering system is periodically tested to verify the required accuracy. If the accuracy of the metering is outside the required accuracy limits, the metering system shall be immediately re-calibrated. A test certificate shall be issued at the end of each test to confirm the accuracy of the metering circuit and, if re-calibration was necessary, to record the tested values and re-calibrated values.

Article 112 Testing and calibration shall be performed by an agency that is accredited by the RRB.

Article 113 The metering system shall include check meters, which have to be connected to the same current transformer core than the main meter.

Article 114 Redundant meters (main and check meters) shall be installed depending on the size of the load or generation and shall be connected to separate current transformer cores.

Article 115 Each Agent shall have the right to install redundant meters at his Connection Point(s). Such installations shall be developed at the own cost of the interested Agent.

Article 116 The RTC shall be responsible for collecting metered data from the metering system at the Inter-connectors.

Article 117 Bi-directional meters shall be installed in Connection Points where power can flow in both directions to separately meter energy in the injection and extraction directions.

Article 118 The RTC shall implement a process of validating the metered data as received from the field including, as a minimum, the verification of the accuracy of the metering system by analyzing the last date of test and calibration. The main and check meter values should not differ by more than the established percentage.

4.3. SCADA AND DATA EXCHANGE

Article 119 Technical facilities shall be installed in the TNM for the exchange of the following information with the RTC:

119(a) Status indications of circuit breaker, isolator switches, and earth switches;

119(b) Analog measurement of active and reactive power flow, voltages and frequency; and,

119(c) Selected protection information.

Article 120 The technical facilities shall comply with the following minimum requirements:

120(a) Double-bit status indications;

120(b) Three-phase active power and reactive power measurement;

120(c) Single-phase voltage measurement; and

120(d) Support open SCADA protocols to allow interface.

4.4. TELECOMMUNICATION INSTALLATIONS

Article 121 The RTC shall have and maintain adequate and reliable telecommunication facilities with the TSO to ensure that there is effective exchange of information to perform its functions. Wherever possible, there should be back-up facilities.

Article 122 The telecommunication facilities shall include:

122(a) Direct (voice) telecommunication channels between the MSC of the RTC, the TSOs and TFOs if they are different from the TSO. Alternate and physically independent telecommunication channels may include voice circuit via the TNM or via the public telecommunications network;

122(b) Data communication channels to support the metering; and,

122(c) Data communication channels to support the SCADA.

Article 123 The reliability and availability of the communication system(s) shall be of adequate quality to support the functions and responsibilities of the RTC.

Article 124 The communications center of the RTC shall include a voice recording system to record all voice communications and dispatch instructions during real-time operations. The recording of these voice communications should be kept for at least three (3) months for reference when needed.

5. OPERATIVE AND TECHNICAL COORDINATION OF THE TNM

5.1. INFORMATION REQUIREMENTS AND OPERATIVE DATA BASE

Article 125 The Operational Planning Working Group, in consultation with the RTC and the TSOs, shall perform periodic evaluations of operative security and analysis of transmission failures and perturbations that took place in the TNM. To perform these evaluations specialized power transmission system simulators shall be used. The information shall be made available in the Regional Database.

5.2. PLANNING STUDIES OF THE OPERATION OF THE TNM

Article 126 The Operational Planning Working Group, together with the RTC, shall perform the operational planning.

Article 127 Operational planning shall be split in two main processes: i) Cross-border Trading planning, and ii) electric operative planning.

Article 128 Planning period for Cross-border Trading planning shall be between six month and two years ahead. Planning period for electric operative planning shall be between one year and two years ahead.

Article 129 Cross-border Trading planning's main objectives are the following:

I. possible cross–border trading scenarios estimation;

II. identification of possible supply problems or restrictions in the Countries; and,

III. evaluation of potential actions from where other countries could collaborate to mitigate or avoid these problems.

Article 130 The electric operative planning shall require periodic evaluations of the security and quality of service for the medium- and long-term. These evaluations are meant to verify that the operation meets the established Performance Standards.

Article 131 The electric operative planning should be updated at least every six months or even more frequently if necessitated by special circumstances.

Article 132 The results of the electric operative planning should be flexible so that they can be adapted to technical and economic changes in the region, always meeting the security, quality and reliability requirements of the region.

Article 133 The TSOs and the TFOs shall participate in the working groups that the Operational Planning Group may establish, so they may discuss the operating plans, make studies on operative security or investigate the causes of incidents that occurred in the TNM. They shall make available their respective information, the results of their studies and those evaluations that they and/or other experts may have made.

Article 134 The data and information that must be taken into account to perform the operative planning studies shall include demand forecasts, generation availability, expansions of the TNM or to the national grids, and the Performance Standards. All of the needed information should be available in the Regional Database.

Article 135 Each TSO shall provide the RTC with its demand forecasts for the next year on a monthly basis, and its best estimation for the following two years on the same basis for reference purposes. Forecasted demand shall be specified for each node of the TNM located in its country. These forecasts shall be presented on November 15th each year.

Article 136 Each TSO shall provide the RTC with daily demand forecasts for the following month, in each node of the TNM that is located in its country at the 25th of each month. The demand forecasts shall include active power and reactive power requirements for each sub-station that is part of the TNM.

Article 137 The TSO shall provide weekly forecasts to the RTC whenever is not able to provide daily forecast as established in Article 136 . In this case the RTC shall apply typical daily distribution factors calculated on the basis of available historical data.

Article 138 The Regional Demand estimation/ load forecast shall be performed by the RTC in accordance with the forecast supplied by the TSOs and the provisions of this PTOA-GSC. The RTC can prepare its own demand forecast if it considers that the information provided by the TSOs is not reliable. The Regional Demand estimation shall be prepared for a period of up to the succeeding three years.

Article 139 The TSOs shall provide the RTC with their load estimates that may be shed when required, in discrete blocks and with the arrangement details of such load shedding.

Article 140 Each TSO shall furnish realistic category-wide demand in their respective countries along with details of essential loads, details of power cuts imposed or to be imposed, and specific requirements, if any.

Article 141 The RTC shall maintain this information in the Regional Database for the purpose of demand estimation and shall be equipped with state-of-the-art tools for demand forecasting.

Article 142 The results obtained from the operative security studies shall be presented as technical reports, which shall be available to the TFOs, the TSOs and the Agents.

5.3. OPERATION PLAN FOR EMERGENCIES

Article 143 The RTC, jointly with the OPWG and the TSOs, shall develop an Operation Plan for Emergencies. This plan should provide the operative measures that allow them to face contingencies in the TNM that may compromise the fulfillment of the Performance Standards.

Article 144 The Operation Plan for Emergencies shall contain the details of operations and actions needed to re-establish the TNM to a normal operative state as soon as possible. It shall also contain the operative coordination actions that have to be performed between the MSC and the TSOs .

Article 145 The Operation Plan for Emergencies shall describe the measures that the TSOs , in coordination with the MSC, have to adopt when:

145(a) There arises an Emergency Operation State

145(b) Some events arise such that the accomplishment of the Performance Standards proves not possible.

Article 146 The RTC shall present to the RRB the developed Operation Plan for Emergencies and shall coordinate the actions needed for its implementation.

5.4. INFORMATION OF INCIDENTS

Article 147 The local TFO has the obligation of reporting the RTC and the corresponding TSOs of each event where the TNM facilities fail in supplying the demand or in each event of an outage in generation. It shall provide a detailed description of the events that occurred as well as the actions that were taken for the re-establishment of the TNM.

Article 148 The TFO that was involved in the incident shall issue the following reports on abnormalities and perturbations:

148(a) A first report with the analysis in real time of the incident, detailing the sequence of events that occurred, a list of the facilities that were affected by the incident, the consequences on the TNM (loss of load, unavailability of facilities, protections that intervened, etc), the immediate actions performed to restore the network to a normal operative state, and preliminary diagnostics of probable causes of the incident. This report shall be sent to the TSO and to the RTC immediately after the incident occurred so that the most appropriate actions can be taken.

148(b) A report containing the results of the preliminary analysis of the incident. This report must be presented to the RTC for its acknowledgement and approval.

148(c) A report containing the final analysis of the incident. This report must be presented to the TSO and to the RTC for its acknowledgement and approval not later than twelve working days after the occurrence of the incident.

148(d) All these reports shall be sent by the RTC to the Operational Planning Working Group and to the RRB.

Article 149 If the final analysis of the incident is not approved by the RTC, comments and observations shall be submitted by the RTC to the TFO. The TFO shall submit to the RTC a new version of the report for its approval not later than seven days after receiving the RTC's comments and observations.

Article 150 If the report on the final analysis of the incident concludes that a malfunctioning in a facility of the TNM –i.e. maneuver elements, protections, control devices– occurred, the TFO involved shall inform to the RTC on the schedule of corrective actions that shall be taken to correct the defect. Ten days after the end of the proposed schedule, the TFO shall send to the RTC and to the TSO a new report detailing the corrective measures that were applied and the corrective actions that were taken.

Article 151 Based on the analysis made by the RTC of the involved TFO's reports, it can then perform a technical audit of the TNM's facilities or on the reports made by the TFO. These audits can be made by the RTC members themselves, or may be delegated to the corresponding TSO. The TFO shall allow for the inspection of its facilities, provide the required information, and accept and comply with the recommendations to mitigate the consequences of the incident and / or avoid its repetition.

6. COORDINATION OF THE OPERATION UNDER NORMAL CONDITIONS

6.1. CROSS-BORDER LOAD FLOWS CONTROL

Article 152 The TSOs shall perform all of the necessary actions to maintain during real-time operation of each scheduled transaction, injection and withdrawal at each node of the TNM.

Article 153 Each country shall operate as one or more control areas, and the delimitation shall be clearly specified and agreed upon with the RTC.

Article 154 The TSO that operates each control area shall keep enough reserve levels to allow for the continuous generation and load balancing within its control area, and to fulfill the scheduled injections to and withdrawals from the TNM; as well as to provide adequate contribution for regulation over the TNM.

Article 155 Each TSO shall perform the necessary corrections on the scheduled transactions, injections and withdrawals at each node of the TNM. Whenever possible, control of scheduled exchanges through Interconnectors between control areas shall be done automatically through the use of AGC.

Article 156 In case AGC is not available within a control area, the necessary control on the involved part of the TNM shall be done manually. The TSO shall provide enough reserve by mean of available resources within its governed control area in order to maintain scheduled Cross-border Transactions.

Article 157 If AGC is unavailable in a control area during a contingency, manual procedures shall be done to correct deviations on both frequency and load flow through the Interconnectors. The RTC shall coordinate with all of the affected TSOs to accomplish both functions over the TNM during contingency situations: frequency regulation and load flow control through inter-connectors.

Article 158 The RTC shall coordinate with each TSO on the operation of available frequency control devices in order to maintain frequency quality over the TNM.

Article 159 The RTC, in coordination with the TSOs, shall be able to perform the necessary corrections according the Performance Standards to the time deviations accumulated in the SER as a consequence of frequency variations.

Article 160 The RTC shall coordinate with each TSO the operation of available devices for voltage regulation in order to maintain adequate voltage levels at each node of the TNM according Performance Standards.

6.2. DEVIATIONS IN THE REGIONAL ECONOMIC DISPATCH

Article 161 Administration of scheduled transactions deviations shall be performed in real time by the RTC through MSC aiming preservation of quality, security and economy of regional exchanges.

Article 162 When deviations respecting scheduled quantities are unavoidable, the TSOs shall maintain them at the lowest possible level according the Performance Standards, aiming to maintain the opportunity transactions scheduled in the Regional Economic Dispatch.

Article 163 In case a TSO does not maintain the scheduled Cross-border Load Flows, penalizations specified in Article 323 and Article 324 shall be applied to that TSO.

7. COORDINATION OF THE OPERATION DURING OUTAGES OR DISCONNECTIONS

7.1. PRINCIPLES FOR THE OPERATION IN EMERGENCY

Article 164 In a normal operative state, the disconnection of facilities and equipment of the TNM shall be made by each TSO following the programming of the operation that was established by the office in their Country and the scheduled Cross-border Transactions.

Article 165 Whenever an emergency occurs in the TNM during the normal operation, each TSO shall immediately apply the measures and the established actions for coordination with the other TSOs. They may also ask the MSC to coordinate the joint measures in order to mitigate the consequences on the TNM and the national networks.

Article 166 When a forced outage in the transmission system gives rise to a restriction in the transmission capacity of the TNM, the involved TFO shall alert to the respective TSO about this situation. The TSO shall then conduct the necessary actions within its country or with other TSO if another control area is affected to restore normal operation conditions. If necessary, according its own criteria the affected TSO is able to ask the MSC to coordinate the necessary re-dispatch operations. When the circumstances make it necessary, the criteria of Regional Demand Control detailed in Title 7.2 can be applied.

Article 167 In cases where total disconnection of generation and load in one or more areas of the TNM occur, the MSC shall coordinate with the TSO affected the operations for re-establishing the network. Each TSO shall recover its own network and obtain the balance between generation and demand in coordination with the respective TFO, handling the synchronization operations of their networks until complete integration with the TNM. The MSC shall be responsible in continuously supervising the re-setting process of the TNM.

Article 168 In case of potential total disconnection of generation and load in the TNM, with this situation of total collapse being confirmed by MSC, the recovery actions shall begin from zero voltage. Each TSO shall instruct the Agents of its jurisdiction to initiate the resetting process and to split up the national networks into isolated sub-systems, according to a pre-established recovery plan. In each isolated sub-system, the respective TSO shall carry out the operations for reestablishment until the level of demand reconnected is higher enough to make possible the recovering according to the available generation in the respective control area. Once the balance level is reached, each TSO shall report to the MSC on their availability to interconnect itself to the TNM. The TSO shall then coordinate with the TSO of the neighboring countries the operations of synchronization of the networks of its jurisdiction until them are fully integrated to the TNM.

7.2. Regional Demand Control

Article 169 Regional Demand Control encompasses all processes by which the MSC of the RTC carries out the procedures that enable re-scheduling of Cross-border Transactions under or after an Emergency Operation State or when such activity becomes necessary in order to preserve the fulfillment of the Performance Standards.

Article 170 The detailed provision is required to enable the MSC to ask the TSOs of the Countries involved in the emergency to achieve a reduction of Cross-border Load Flows to avoid operating problems on all or part of the TNM. MSC shall instruct the affected

TSOs to modify scheduled Cross-border Load Flows in a non-discriminatory manner respecting the Agents that are participating in Cross-border Transactions.

Article 171 The need for Regional Demand Control shall arise on account of the following conditions:

I. Variations in generation-demand from the scheduled values, which cannot be absorbed by the network;

II. Unforeseen generation / transmission outages resulting in reduced transmission capacity availability; and,

III. Heavy reactive power demand causing low voltages, which may introduce collapse risks if scheduled Cross-border Load Flows are maintained.

Article 172 As part of the Regional Economical Dispatch the RTC shall match the consolidated Regional Demands with consolidated generation availability from various sources and exercise Cross-border Load Flows control to ensure there is a balance between the energy availability and the scheduled demand plus losses and any requirement of generation reserve.

Article 173 In case of emergency during real time operation, the TSOs of the countries involved shall ask the MSC to coordinate the mitigation measures with all other TSOs.

Article 174 Independently of whether the MSC considers mitigation of the effects of the emergency as possible or not, it shall determine the measures that can be implemented with mitigation purposes, including re-dispatch of generation and Regional Demand control.

Article 175 Regional Demand Control shall be exercised by the TSOs through direct instructions from the MSC. No Regional Demand shed by operation of under frequency relays shall be restored without specific instructions from the MSC.

7.3. LOAD CRASH

Article 176 In the event of a load crash in the TNM due to a weather disturbance or any other reason which affects more than one Country, or at the request of the TSO of the Country where the load crash occurred, the situation shall be controlled by the MSC in coordination with the corresponding TSOs, by the following methods in descending priorities:

I. Backing down of hydro stations for short period immediately.

II. Lifting of the load restrictions, if any.

III. Exporting the power to other GMS or neighboring countries not involved in the crash.

IV. Backing down of thermal stations.

V. Closing down of hydro units (subject to non-spilling of water and effect on irrigation).

Article 177 The Operational Planning Working Group shall periodically review the methodology provided in Article 176 .

8. OUTAGES COORDINATION

Article 178 Outages Coordination is the process that allows to the OPWG –and the RTC to conduct a voluntary process of coordinating the maintenance outages of TNM transmission facilities and large generation units in order to optimize operation costs, while maintaining system security to the possible extent.

Article 179 Each TFO and Agent with generating units larger than 200 MW shall provide to the RTC their outage program for the next year.

Article 180 The OPWG shall be responsible in analyzing the impact of outage schedules on TNM security and costs. The OPWG shall use computer simulation programs to assess this impact.

Article 181 Based on the information obtained from the simulations, the OPWG and the RTC shall jointly prepare an alternative schedule for outages in order to minimize negative impacts. This new schedule shall keep the expected time that the facility needs to be out of service, changing only the dates when the outage will take place within the same year.

Article 182 The OPWG –and the RTC shall organize meetings with the TSOs, the TFOs and the Agents to coordinate the outages schedule in order to minimize negative impacts. All changes in the original schedule shall be optional for the TFOs and the Agents.

Article 183 The RPTCC shall be informed by the OPWG –and the RTC whenever they identify cases where the original schedule may produce any of the following events:

I. Major TNM disturbance

II. System Isolation

III. Black out in one or several Countries

IV. Any other event in the system that may have an adverse impact on system security by the proposed outage.

In theses cases the RPTCC shall recommend to the respective TSO to force the owners of the facilities whose outage may produce the situations mentioned above, to change the planned outage date.

Article 184 Once the definitive maintenance schedule is agreed with the TFOs and the Agents the OPWG shall prepare the Outage Program, which shall contain details like identification of unit or facility, generation availability affected due to such outage and outage start date and duration. Those outages included in the Outage Program shall be considered as Planned Outages.

9. SERVICE QUALITY AND RELIABILITY

9.1. *CHARACTERISTICS OF THE QUALITY AND RELIABILITY REGIME*

Article 185 The TNM shall be operated maintaining the quality levels established in this PTOA-GSC. In order to do that, it shall be maintained a homogeneous quality level whenever possible, what means that quality level should be the same in all stages of planning and operation management. To fulfill this objective, the RTC activities, the TSOs and the agents participating in Cross-border Transactions shall be consistent with the criteria and conditions established by this code, considering also the audit and control mechanisms required to monitor the achievement of the intended reliability, quality and security levels.

Article 186 The equipment to be installed in the TNM, included the connection points, shall comply with the design criteria established in the Transmission Design Code chapter**.** They shall allow the operation of the TNM following the Performance Standards.

Article 187 The facilities and equipment related to the TNM shall comply with the environmental requirements that are in place in each country, plus the ones established at regional level.

Article 188 The TNM and all facilities connected to it shall be programmed and operated following the Performance Standards established in this PTOA-GSC. Aiming this the TSOs shall program the Cross-border Load Flows resulting from the PPAs, and inform the RTC of the remaining transmission capacity for Opportunity Cross-border Transactions, ensuring the full compliance of the Performance Standards.

Article 189 The RTC shall ensure the TNM operation is done in accordance with the quality levels specified in the present PTOA-GSC. Therefore the RTC shall execute and ensure the execution of those actions that it considers necessary for the fulfillment of this requirement in normal operation conditions as well as under emergency conditions.

9.2. *SERVICE QUALITY OBJECTIVES*

Article 190 The following service quality objectives are initially established for the facilities that are part of the TNM:

190(a) Disconnection hours per year in concept of Planned Outage, by line with a voltage level between 100kV –and 219 kV: 20 hours every 100 km.

190(b) Disconnection hours per year in concept of Unplanned Outage, by line with a voltage level between 100kV –and 219 kV: 10 hours every 100 km.

190(c) Disconnection hours per year in concept of Planned Outage, by line with a voltage level between 220kV –and 500 kV: 15 hours every 100 km.

190(d) Disconnection hours per year in concept of Unplanned Outage, by line with a voltage level between 220kV –and 500 kV: 10 hours every 100 km.

190(e) Number of disconnections per year in concept of Planned Outage, by line with a voltage level between 100kV –and 219 kV: 2 every 100 km.

190(f) Number of disconnections per year in concept of Unplanned Outage, by line with a voltage level between 100kV and 219 kV: 2 every 100 km.

190(g) Number of disconnections per year in concept of Planned Outage, by line with a voltage level between 220kV and 500 kV: 1 every 100 km.

190(h) Number of disconnections per year in concept of Unplanned Outage, by line with a voltage level between 220kV and 500 kV: 1 every 100 km.

190(i) Disconnection hours per year in concept of Planned Outage, for transformers and compensation equipment: 15 hours.

190(j) Disconnection hours per year in concept of Unplanned Outage, for transformers and compensation equipment: 15 hours.

190(k) Number of disconnections per year in concept of Planned Outage, for transformers and compensation equipment: 1.

190(l) Number of disconnections per year in concept of Unplanned Outage, for transformers and compensation equipment: 1.

190(m) Disconnection hours per year in concept of Planned Outage, for connection equipment: 15 hours.

190(n) Disconnection hours per year in concept of Unplanned Outage, for connection equipment: 15 hours.

190(o) Number of disconnections per year in concept of Planned Outage, for connection equipment: 1.

190(p) Number of disconnections per year in concept of Unplanned Outage, for connection equipment: 1.

Article 191 The assessment procedure for establishing the interruption duration and numbers shall be based on records that shall keep the date, time and duration of all interruptions. A series of short-term interruptions in a single auto-reclose sequence of protection equipment shall be classified as a single forced interruption. Where an interruption results from under-frequency load shedding by a generating facility, the accountability for such an interruption shall not be allocated to the TFO whose transmission facility had the outage.

Article 192 Two years after the validity of this PTOA-GSC, the RRB shall establish objectives for the following magnitudes:

I. Voltage flicker, which is the modulation of the supply voltage amplitude that can be observed as a fluctuation of the light intensity of electric lighting.
II. The total harmonic distortion, defined as the square root of the sum of the squares of the per cent r.m.s. value of the h_{th} harmonic or interharmonic voltage component, for the N lowest harmonic considered.

III. Voltage unbalance: this arises in a polyphase system when the magnitudes of phase voltages or the relative phase displacement between the phases (or both) are not equal.
IV. Voltage dips, which are characterized by the measurement of the dip duration below the dip threshold, and by the dip magnitude

Article 193 For each of the magnitudes defined in the Article 194 , the RRB shall define:

I. Assessed level: The level used to evaluate the measured values at a particular site against compatibility levels.
II. Assessment Method: A specified measurement procedure to produce an assessed level.
III. Compatibility level (electromagnetic compatibility level): The specified disturbance level at which an acceptable, high probability of electromagnetic compatibility exists. Until the RRB set the standards, the IEC 161-03-10/A shall be used.

9.3. PENALTIES REGIME

Article 194 Two years after of the validity of this PTOA-GSC, the RRB shall establish a penalty regime to promote the achievement of the Service Quality Targets set in the Title 9.2.

Article 195 The penalties shall be applied to the TFOs when the Service Quality Targets are not achieved. Such penalties shall be based on discounts on their remuneration, which shall be applied when the "out of service" periods, or the number of disconnections of their assigned facilities are greater than the ones specified in the Service Quality Targets. The penalties shall be applied by facility.

10. ANCILLIARY SERVICES

Article 196 The ancillary services in the scope of the TNM include:

196(a) The Area Control, which encompasses the functions of the area control operator that allow generation planning and Cross-border Trading as well as the real time control of the generation and the load balance. The definition of the service is oriented towards the maintenance of the generation and transmission security and the anticipation of emergency situations.

196(b) Reactive compensation and generators voltage control, which encompasses the supply and acquisition of reactive power by the generators so as to maintain the transmission system voltage between the required range.

196(c) Regulation, which encompasses the use of generators equipped with regulators and automatic generation controls to maintain the balance between generation and load between a control area in order to keep the minimum performance of the previously determined system.

196(d) Spinning reserve, which encompasses to maintain availability of generation response from those generating units synchronized with the network and under the control of regulators and automatic controls. Generation required under this service is delivered to the system in periods not longer than 5 minutes in order to correct the balance between generation and load in response to an imbalance associated to a loss of generators and/or lines.

196(e) Automatic generation disconnection: corresponds to the disconnection of power blocks in accordance to a determined priority, when the frequency descends below specified values associated to each block.

196(f) Black Start capability: the capability of a generation unit to acquire a normal operative condition starting from a total stop of this unit without the support of the electric network. Once operative, the unit is capable of supplying the electric network in order to help other units in their start after the occurrence of a blackout.

Article 197 In relation to Cross-border Trading and in order to avoid unplanned transfers or deterioration of the quality of service, the TSO of each country has the obligation to balance its own generation and load as well as the agreed transactions, in a way that ensures the fulfillment of the Performance Standards in the Control Points of the TNM.

Article 198 In case a TSO considers that it cannot fulfill the obligation established in Article 197 , or that it results economically inconvenient to provide the service with its own resources, it can buy the services in the available offer of other Member Countries through a bilateral arrangement with other TSOs. The TSO may require the intervention of the RTC to facilitate those agreements.

11. CALCULATION OF THE TRANSMISSION CAPACITY

Article 199 During Stage #2, transmission capacity shall be computed with some simplifications. The basic concept for performing this calculation is that the TSOs of each Country shall compute the transmission capacity available in their networks, and the RTC shall integrate those capacities in its model for the Regional Economic Dispatch.

Article 200 The OPWG, with the support of the RTC and the TSOs, shall develop a harmonized basic procedure between TSOs for calculating transfer capacities. This means that the basic scenarios have to be commonly agreed and that the calculation procedures of all TSOs are comparable. This approach helps leads to easier agreements between TSOs about concrete values, to check their global consistency and to ensure in a best way transparency towards decision-making. This procedure shall be presented in a report to the RRB. The procedure shall be based on the general criteria established in this PTOA-GSC and on the fulfillment of the Performance Standards.

Article 201 The RTC, using the procedure developed by the OPWG, shall annually verify the Transmission Capacity of every line or group of lines that form part of the TNM. The Transmission Capacity determined by the RTC shall be made available for transactions; while discounting the security margins that might be required.

Article 202 A set of maximum exigency scenarios shall be defined, consistent with the ones required for each country to ensure fulfillment of Performance Standards.

Article 203 TNM operation shall be simulated for the scenarios defined in Article 202 with full availability of the transmission system except those elements that are temporally non-available because of maintenance. Under these scenarios the contingencies covered by the Performance Standards shall be analyzed, verifying their fulfillment.

Article 204 The RTC shall evaluate if an eventual reduction of the Transmission Capacity of a facility of the TNM affects the existing PPA. If this is the case, the RTC shall evaluate the reasons and analyze alternative possible ways of operating the TNM so as to avoid the constraints in the PPA execution.

Article 205 The RTC shall submit to the RRB the results of the projection and the transmission capacities every October 1st in order to allow its use in the Regional Economic Dispatch starting January 1 of next year.

Article 206 The RRB shall approve these projections and then inform the agents as well as publish the information in its web site. If the RRB considers the projections do not comply the required procedures, it may require the RTC to do the needed corrections and perform new projections.

12. INTER-TFO COMPENSATION MECHANISM (ITCC)

12.1. GENERAL CRITERIA

Article 207 The TFOs shall receive compensation for costs incurred as a result of hosting Cross-border Load Flows of electricity on their networks.

Article 208 The compensation provided in Article 207 shall be paid by the Agents from which Cross-border Load Flows are originated and the Agents to which those flows end. Compensations shall be calculated according the Inter-TFO Compensation Mechanism and paid on the basis of power injected or withdrawn from the TNM by the Agents.

Article 209 The Inter-TFO Compensation Mechanism (ITCC) consists of:

209(a) The TFO's Remunerations Regime: it defines the methodology to establish the Authorized Revenue that each TFO can receive.

209(b) The Tariff Regime for the Agents of the TNM: it defines the methodology to collect the Authorized Revenue of all the TFO among the Agents that schedule Cross-border transactions.

209(c) The ITCC itself, which is the result of assigning to the Agents the responsibility of payment of the Authorized Revenues, following the methodology established in this Title of the PTOA-GSC.

Article 210 The Authorized Revenues of each facility of each TFO shall be composed by:

210(a) A connection charge: It is the revenue received for operating and maintaining, according to the required quality of service, all the connection and transforming facilities needed to connect to the TNM the Agent's facilities or other TFO's networks. This remuneration shall also include capital costs and a reasonable return on investment. The Connection Charge shall be applied in Stage #3 and #4.

210(b) A remuneration for using the TFO's facilities that integrate the TNM: It is the revenue that shall be received for operating and maintaining the transmission facilities dedicated to connect the different nodes of the TNM according to the required quality of service. These charges include the remuneration to: lines with their connection fields to a substation, compensation elements connected to lines and transformers that connect nodes which are considered part of the TNM. This remuneration shall also include capital costs and a reasonable return on investment.

Article 211 Agents that schedule Cross-border Transactions shall pay the transmission losses, and therefore they are not part of the ITCC.

12.2. AUTHORIZED REVENUES OF TFOS

Article 212 The total Authorized Revenue that each TFO shall receive in a year shall be equal to the sum of the Authorized Revenues corresponding to each one of its facilities.

Article 213 The capital cost that shall be recognized and therefore shall compose the Authorized Revenue shall be calculated according to the following criteria:

213(a) For the expansion of facilities associated to a PPA in which it has been negotiated an additional capacity over the capacity needed by the PPA the capital cost shall be linked to the additional amount negotiated.

213(b) For expansions resulting from the Planned Expansions, the capital cost shall be the investment cost resulting from an international public bidding process to build the facility.

213(c) For the TFO's facilities, the capital cost shall be linked to the scheduled use of the facilities. The capital cost of a specific facility which is part of the TNM, shall be valued according to the Annual Standard Cost of the facility, calculated according to the dispositions established in the Article 214 of this PTOA-GSC.

Article 214 The Annual Standard Cost of a certain facility shall recognize the following components:

214(a) The investment costs calculated considering as assets the actual facilities valued at the Unit Standard Costs.

214(b) A period for the construction no longer than two years; the investment costs calculated in the previous article shall be distributed along this period.

214(c) The investment cost equal to the net present value of the investments distributed along the construction period, calculated at the moment of commissioning using the discount rate established by the RRB.

Article 215 Once the investment cost of a facility is established, it can only be modified by changes in the Unit Standard Costs or the discount rate, which shall be reviewed every year by the RRB.

Article 216 The Authorized Revenue per year of a TFO's facility considered as part of the TNM shall be calculated every year and shall be determined as the sum of:

216(a) The annuity of the capital cost established in Article 214 , considering the discount rate established by the RRB and the life of the facilities also established by the RRB. For existing facilities this component shall be zero once the amortization period of the facility is ended. The amortization period shall begin once the facility is commissioned. The information on the commissioning date must be stated by the TFO and confirmed by the corresponding TSO.

216(b) The efficient costs of administration, operation and maintenance that shall be established by the RRB as a percentage of the total capital cost. The recognized administration, operation and maintenance costs shall be those of efficiently operated companies and its calculation shall be based in a benchmarking of international transmission companies adjusted in such a way that local costs and productivity in the GMS is taken into account. Until the RRB establishes this value, a percentage of 2% shall be used.

216(c) Other costs needed to perform the activity, calculated as a percentage of the capital costs of each facility that shall be established by the RRB. Until the RRB establishes this value, a percentage of 1% shall be used.

Article 217 Once the amortization period of the facilities is finished the Authorized Revenue of the existing facilities shall be limited to: (1) the efficient costs of operation, maintenance and administration and (2), other costs needed for functioning.

Article 218 If a facility of the TNM is still in service after its amortization period, the RRB can recognize in addition to the efficient costs of operation and maintenance the investment cost of control installations, communication and protections that may have been renewed or must be renewed for a safe and reliable operation of the facility.

Article 219 The Authorized Revenue of facilities owned by TFOs shall be equal to the Authorized Revenue calculated in Article 213 multiplied by the coefficient established in the Article 224 of this PTOA-GSC.

12.3. CALCULATION OF ITCC

Article 220 The ITCC shall be established every six months beginning November the 1st and May the 1st of every year.

Article 221 The Revenue to Collect for each facility of the TNM is calculated as the annual Authorized Revenue divided by two and multiplied by the corresponding coefficient that represents the use of the facility for the semester considered. The calculations are made according to the methodology established by Article 224 of this PTOA-GSC.

Article 222 The ITCC that each TFO shall receive shall be collected through payments made by the Agents. The determination of the payment that corresponds to each Agent shall be based in the net injections and net withdrawals that the Agent makes from the TNM as a result of the Regional Economic Dispatch.

Article 223 The ITCC shall be calculated by the RTC twice a year and submitted to each of the national TSO disaggregated as follows:

I. The payments that each Agent must do for the purchases of energy through Cross-border transactions.

II. The payments that each Agent must do for the selling of energy through Cross-border transactions.

Article 224 The guiding principle for the ITCC is to assign to the Agents the responsibility of paying for the facilities of the TNM according to the injections or withdrawals of energy that they had made. The total payments that the Agents must do within each semester are equal to the Revenue to collect for the same semester.

224(a) The calculation of the ITCC for a semester shall be based on the results of the Regional Economic Dispatch performed the same semester of the previous year. For the first year of operation the RTC shall estimate the flows based on simulations of the Cross-border Transactions.

224(b) The coefficient for the use of a facility of the TNM in a transaction shall be equal to the relationship between the sum of the absolute value of the Transit Load Flow in the facility extended to all the hours of the semester according to the Regional Economic Dispatch, and the Transmission Capacity of the facility multiplied by the total hours of the semester, i.e.

$$Cu_f = \frac{\sum_t \left|F_{f\,t}\right|}{CAP_f * HS}$$

Where: Cu_f is the coefficient that represents the use of the facility 'f' owned by a TFOs in a given semester; 't' denotes each hour of such semester; F_t represents the average load flow through the line 'f' along hour 't'; CAPf denotes the transmission capacity of line 'f'; and HS is the number of hours of the semester. For all the other facilities, i.e. those planned or that are associated to a PPA, Cu_f is equal to 1 (one).

224(c) The hourly Transit Load Flows associated to the Regional Economic Dispatch are those that were obtained by the RTC as result of the day ahead Regional Economic Dispatch performed for each hour of the same semester of the previous year.

224(d) For each hour, the RTC shall calculate the Transit Load Flows through the TNM using the accepted Bids and Offers. Using the Matrix H described in the Annex 2 to this PTOA-GSC, and taking into account the configuration of the TNM previewed for the semester for which the calculations are being made.

224(e) From this process we can also be obtain the Net Injections and Net Withdrawals of each Country, as the sum, for each hour of the Cross-border Load Flows calculated following the procedure described in the Article 224(d) .

Article 225 The ITCC shall be calculated as follows:

225(a) The hourly Net Injections and Net Withdrawals to be used for the calculation of the ITCC shall be calculated on the basis of load flows resulting of the Regional Economic Dispatch for each hour of the same semester of the previous year for which the ITCC are being calculated, following the procedure described in the Article 224(e) .

225(b) The integrated Net Injections and the integrated Net Withdrawals are calculated as the sum extended to all the hours of the semester of the hourly Net Injections and Net Withdrawals.

225(c) The ITCC shall be calculated for each semester for each Country according the following expressions:

I. The ITCC for the demand of a country "p" shall be calculated as:

$$ITCCD_{ps} = \frac{\Sigma i \ (IAR_s * \Sigma_i NW_{ips})}{(\Sigma_i \Sigma_p NI_{ips} + \Sigma_i \Sigma_p NW_{ips})} \qquad i= 1,,,,CHN$$

Being:

NW_{ips} the Net Withdrawals corresponding to the Calculation Hour "i", country "p" and semester "s".

NI_{ips} the Net Injections corresponding to the Calculation Hour "i", country "p" and semester "s".

CHN total number of Calculation Hours of semester "s".

IAR_{js}: Authorized Revenue to Collect by the facility "j" in the semester "s"

II. The ITCC for the generation of the country "p" shall be calculated as:

$$ITCCG_{ps} = \frac{(\Sigma_j \ IAR_{js} * \Sigma_i NI_{ips})}{(\Sigma_i \Sigma_p NI_{ips} + \Sigma_i \Sigma_p NW_{ips})} \qquad i= 1,,,,CHN$$

Article 226 The Agents of each country shall pay every month to the RTC the sum of the quantities $ITSCG_p$ plus $ITCCD_p$ divided by six.

12.4. PAYMENT OF THE ITCC

Article 227 The TSO of each of the Member Countries shall pay to the RTC the amounts resulting from the application of the criteria established the Article 226 of this PTOA-GSC. The amount corresponding to a given month shall be deposited in the bank account established by the RTC before the 10th day of the following month.

13. REGIONAL TRANSMISSION PLANNING

13.1. GENERAL CRITERIA

Article 228 The Regional Transmission Planning activity includes the execution of the following tasks:

228(a) Long Term Planning of the TNM Expansion aims to identify such expansions of the TNM that maximize the Social Welfare of the Agents and consumers of the Member Countries. Social Welfare shall be calculated as the consumers' surplus plus the producers' surplus. The Long Term Planning shall be prepared with a timeline of at least ten years, but could be extended by the RRB if it considers it necessary to improve the quality of the results. The process of Long Term Planning shall consider that the countries of the region may make independent decisions on the expansion of their internal networks and on new generating power stations. The process of Long Term Planning shall consider as an external data (provided by the TSOs of each country) the final decisions on the installation of new plants or transmission facilities.

228(b) Medium Term Diagnosis of the TNM: The objective of the process of Medium Term Diagnosis of the TNM is (1) to review the capacity of the TNM to transport the present and future patterns of the generation and the demand; (2) to develop recommendations for a program of small expansions and/or modifications of the facilities of the TNM to maintain the security and reliability levels as have been defined in the Performance Standards in Title 3.4 of this PTOA-GSC; (3) To identify adjustments to the protection systems; and, (4) To analyze the convenience of changing change the switchyard equipment to others with greater capacity. The Medium Term Diagnosis shall be made with a timeline of three years

228(c) Evaluation of other expansions proposed by GMS countries and reported by their representatives to the RPTCC.

Article 229 As a result of the Regional Transmission Planning process, the SPWG shall formulate the following documents:

229(a) an Annual Report on Long Term Planning (LTP), which shall be presented for consideration of the RPTCC every November 30th.

229(b) an Annual Report on Medium Term Diagnosis, which shall be presented for consideration of the RPTCC every October 31st

229(c) Reports on those expansions of the countries' transmission networks that may affect the TNM which will be presented two months after the SPWG obtains the information on the project of the country where the expansion is located.

229(d) Other reports on specific subjects requested by the RRB.

13.2. SCOPE OF THE LONG TERM PLANNING (LTP)

Article 230 The main objective of Long Term Planning (LTP) shall be to identify those TNM expansions that allow for:

230(a) An increase in the cross-border transmission capacity that produces a positive Social Welfare increases for the GMS. The SPWG shall focus on those extensions whose benefits are distributed among a high number of Member Countries, and where it is not probable to form a coalition to handle the expansion agreement between the countries.

230(b) As a particular case from the previous article, those expansions that allow for a reduction of variable costs in the regional scope shall be considered. In these cases, the SPWG shall compute the reduction on energy prices at each country multiplied by the respective demanded energy.

230(c) Improvement of the service security and reliability at a regional level: for considering these expansions the studies should demonstrate that the net present value of the valuation of the diminution of the avoided unserved energy is greater than the net present value of the investments and the corresponding costs of operation and maintenance. The economical valuation of the unserved energy shall be calculated using the VOLL established by the RRB.

Article 231 The Regional Transmission Planning shall follow the guidelines specified below in relation to the expansions on generation or transmission decided by Agents:

231(a) The Regional Planning shall avoid facing expansions that mean that new individual generating plants or great demands located far from the TNM do not pay the costs of connecting its assets to the TNM.

231(b) In order to consider long planning horizons, it is necessary to make assumptions on the future expansion of the generation in each country. In first term it shall be used the information provided by the countries on their decisions of expansion that could be considered as firm. For the part of the planning horizon not covered by the expansion plans of the countries, it shall be used a least cost expansion plan or the generation prepared using the optimization models owned by the PWG and the Regional Data Base.

231(c) The planning studies shall develop the following tasks for each proposed expansion:

I. Environmental impact and mitigation studies

II. Consumers and producers surpluses

III. Expected changes in the ITCC

13.3. SCOPE OF THE MEDIUM TERM DIAGNOSIS

Article 232 The Medium Term Diagnosis shall have the following targets:

232(a) Review the TNM capacity to transport the expected generation and demand patterns;

232(b) Issue recommendations for a plan of minor expansions or upgrades of the TNM, which allow preserving the system security and reliability on the levels set in the Performance Standards;

232(c) Identify bottlenecks in the TNM or national networks that may deteriorate the security or reliability of the transmission networks of the Member Countries, or reduce the cross-border transmission capacity, and assess the measures or investments that are appropriate to eliminate or mitigate these problems;

232(d) Assess the convenience of changing switchyard equipment, when the interruption capacity of this devices may limit expansions of generation and/or transmission;

232(e) Assess the impact on the TNM of the connection of new large-scale generation plants o transmission facilities in the national networks;

13.4. BASIC PRINCIPLES FOR THE REGIONAL PLANNING

Article 233 The consumers surplus shall be calculated as the difference between the price a consumer is willing to pay for one kWh (with some quality level) and the cost that the consumer is indeed paying for the energy, plus the diminishing of the unserved energy valued at the VOLL. The RRB shall develop the detailed methodology that shall be used to calculate the consumers' surplus, which is based on surveys or on statistical estimations of the demand-price elasticity. For this last case the elasticity shall be calculated for different type of consumers (residential, industrial, commercial, etc.).

Article 234 The producers' surplus shall be calculated as the difference between the quantities or energy sold by producers valued at the selling (market) price and the cost of producing the energy sold. In energy trading, the cost of producing the energy can be substituted by the offers presented by the producers.

Article 235 Until the RRB establishes the methodology for calculation of the consumers' surplus, the target of the regional planning shall be to minimize total net present value of cost to provide energy. The costs that shall be considered are: fuel costs, variable O&M costs of existing facilities; incremental investments in transmission facilities and the respective O&M expenses; savings in incremental investments in generation; and diminishing of the unserved energy..

Article 236 The planning models that shall use the SPWG to optimize the transmission investments should be able to assess the changes in the unserved energy that ate consequence of the investments analyzed:

Article 237 The net present value of the new projects cash flow shall be discounted using the discount rate that shall define the RRB.

Article 238 The SPWG shall be able to identify the benefits, i.e. changes in the social welfare; and incremental cost linked to investments proposed by third parties.

13.5. SYSTEM PLANNING WORKING GROUP (SPWG)

Article 239 The regional planning activity shall be developed by the System Planning Working Group, which shall function as a Working Group within the RPTCC structure. The SPWG shall produce annually the reports mentioned in the 228(c) . These reports shall be presented to the RPTCC in the dates specified by the PTOA-GSC, and shall include the proposal for expansions of the TNM, following the procedures established in Article 241

Article 240 The tasks developed by the System Planning Working Group shall be supervised for an Advisors Committee, whose members must be qualified specialist in power systems planning. These specialists shall be appointed by the RPTCC. The Advisory Committee shall analyze and evaluate the reports prepared by the SPWG, and they shall include their comments and recommendations in the reports. Every time that the OPWG presents the Long Term Planning and Medium Term Diagnosis report, these reports shall include the comments of the Advisors Committee. For the other reports, the SPWG may ask the opinion of the Advisors Committee.

13.6. PROCEDURES AND METHODOLOGY FOR PLANNING ACTIVITIES

Article 241 The SPWG shall fulfill the following procedures:

241(a) For conducting the planning activities the SPWG shall use the information stored in the Regional Data Base.. Use of all other information collected in the region by the SPWG and considered useful for the planning activities by SPWG shall submit the new information collected for planning purposes to the RTC;

241(b) Definition of scenarios: a Base Scenario and Sensitivity Scenarios shall be defined by SPWG for planning activities. The Base Scenario shall be defined with the best estimation or the more probable values of the variables and critical parameters, which are defined in article 241(d) . Sensitivity Scenarios shall consider different expansion plans of the generation, as well as changes in other sensitive variables as demand growth or fuel prices;

241(c) SPWG shall request the RRB the discount rate to be applied for discounting the costs and the cash-flows of expansions projects of the TNM;

241(d) SPWG shall define the basic variables that shall be used: (1) demand forecast, by country and node; (2) technologies that are candidates for generation expansion; (3) capital cost of new facilities; (4) fuel prices forecasts, of those fuels expected to be used in the GMS countries; (5) availability of existent and new generation and transmission facilities (6) new generation projects with regional scale.

241(e) SPWG shall use an Expansions Optimization Model to obtain the maximum social welfare and/or minimum net present value of costs expansion plan, considering the Base Scenario and the Sensitivities. The model shall have the capability to identify expansion plan that minimizes the "maximum regret cost".

241(f) SPWG shall prepare simulations of expected Cross-border Transactions and TNM operation with the optimal(s) expansion plan, for each of the Scenarios – base and sensitivities- considered. This simulation should allow the SPWG to assess the technical and economical feasibility of the expansion plan as a whole, and of the individual projects. It the SPWG deems convenient shall introduce changes in the basic data and repeat the process, starting for running again the Expansions Optimization Model.

241(g) SPWG shall verify the sustainability of the investments defined in the process described in articles 241(e) and 241(f) . Some of the verifications shall include: (1) the rate of return of each project is compatible with the regional rate of discount; (2) the net present value of the costs to meet the demand are, discounted a the rate set by the RRB is positive; (3) the value at risk of the rate of return has a reasonable value. Depending of the results of this analysis, the SPWG can decide to carry out corrections to the parameters of the expansion model and to repeat the process of Optimization of the Expansions.

241(h) SPWG shall analyze the static and dynamic functioning of the RTN, using the Power System Analysis models and define the actual capacity of new transmission lines. The SPWG should be responsible to establish the methodology to analyze the static and dynamic functioning of the RTN using the Power System Analysis models, being a possibility to use the methodology that is described in chapter 11 of this Grid Code.

241(i) To assess the static behavior, the SPWG shall analyze a set of scenarios, which should be described by the topology of the RTN, and patterns of generation and demand in average and extreme conditions: (1) peak and valley demand;(2) dry and wet hydrological conditions; (3) large facilities out of service; etc. It shall be verified that all the electrical parameters as flows and voltage levels are within the limits established in the Performance Standards, as set in the chapter 3 of this Grid Code.

241(j) The static and dynamic studies shall start with the RTN in normal state (N); then it shall be simulated a contingency as the loss of a relevant facility (N-1), as lines, generators or transformers. When there is a credible risk of regional black out, it shall be also simulated some double-contingencies (N-2). For each one of the contingencies that does not produce any black out the expected cost of the unserved energy shall be calculated, which shall be compared with the cost of maintaining the service.

241(k) Assess the technical risks related to the unserved energy and voltage levels, and economic risks; and regret cost linked to develop transmission facilities that finally do not produce he expected benefits because delays in the commissioning of other assets.

241(l) Carry out the economical evaluation of the selected expansions, which at least encompasses calculation of internal rate of return, net present value, regret cost and value at risk.

241(m) Prepare a list of the selected expansions, which shall be presented to the RRB. The projects shall be selected based on the economic evaluation parameters calculated following the requirements stated in the Article 241(l) , and the risks assessment described in the Article 241(k) .

241(n) Prepare the reports detailed in the Article 229 , which shall include the list of projects that are recommended for development. These reports shall be sent to the RRB.

13.7. DEMAND FORECAST

Article 242 The SPWG shall use for its studies the demand forecast provided by the TSO of each country. Nevertheless the SPWG shall prepare independent projections, using its own criteria and models. If the SPWG identifies significant differences between its projections and those provided by the TSO, it shall prepare a report on its diagnostic on the reasons of the differences, and send to the respective(s) TSOs. The TSOs shall analyze this report and answer to the SPWG in a term of five days. Once received the answer, the SPWG shall decide which projection will be used for its studies.

13.8. VALUE OF LOST LOAD

Article 243 The RRB shall develop using own resources or hiring external consultants a study to assess the value of the lost load (VOLL), which shall be used for the planning studies. This study shall be based in surveys, which shall estimate the willingness of consumers to pay to avoid supply interruptions. Until this study is performed, it shall be used a value of 500 US$/unserved-MWh.

13.9. PLANNING MODELS

Article 244 The SPWG and the OPWG shall use mathematical models for developing their activities. These models shall have the characteristics described in the following articles.

13.9.2. EXPANSION OPTIMIZATION

Article 245 The SPWG shall use an “Expansion Optimization Model”, with the following characteristics:

245(a) Ability to maximize the net present value of the expected social welfare, which shall be calculated as the consumers' surplus plus the producers' surplus, during the planning horizon. For calculation of the producer's surplus, the model should account for: fuel costs, incremental capital cost of generation and transmission and O&M expenses. For calculation of the consumers' surplus the model should consider the expected unserved energy, valued of the VOLL.

245(b) Ability to minimize the net present value of the expected cost necessary to meet the forecasted demand. For calculation the mentioned cost, the model should account for: fuel costs, incremental capital cost of generation and transmission and O&M expenses.

245(c) Consider as random variable for calculation of the expected values: (1) unplanned outages of generators and transmission facilities; (2) hydrology; (3) fuel costs; (4) demand. For each study the SPWG shall decide which variables should be considered as random.

245(d) Consider the variables linked to generation or transmission expansions as integers, having the model user the possibility of choosing which variables will be consider as integers.

245(e) Automatically forecast the energy and maximum power demand, by country and node of the RTN, using different rates for each country and/or node.

245(f) Allow the definition of the objective function as: maximize the social welfare, minimize the costs to meet the demand, minimize the maximum regret cost. In all of these cases, it should be possible to define a constraint that social welfare/cost/regret must with a certain probability be greater than some threshold ("value at risk").

245(g) Should be able to identify individual benefits for each Agent, as difference between the scenario with the expansion and the other scenario without it.

245(h) Ability to model the whole TNM, using linear or non-linear representation.

245(i) Ability to optimize the long-term operation of reservoirs.

245(j) Planning horizon of at least 15 years.

245(k) Possibility to define or calculate the "end of game" cost, at the end of the planning horizon.

13.9.3. TNM SIMULATION MODEL

Article 246 The SPWG shall have a model to simulate the short and long term operation of the TNM for Cross-border Trading. This model shall also be used by the OPWG and the RTC. This model shall have the following capabilities:

246(a) Ability to model the TNM, with linear or non-linear model.

246(b) Capacity to consider all of the regional generation.

246(c) Long-term optimization of the reservoir operation, assuming a stochastic behavior of the flows in the rivers where the large reservoirs are located. The model shall keep the spatial and temporal correlations between discharges in different gauging stations in the region. The model shall accept as input historical records and shall be able to generate synthetic series of discharges.

246(d) Automatic calculation of the variable costs of generators, based on heat rate, fuel costs and type of generating unit.

246(e) Long term optimization of the hydro generation, using the concept of "water value", which defines the optimal arbitrage between storing the water or using it immediately for power generation,

246(f) Ability to model failures that produce unserved energy. Calculation of the social cost of the unserved energy using the VOLL.

13.9.4. POWER SYSTEM STUDIES

Article 247 The PWG shall purchase an internationally-used model for power system analysis with the ability to carry out the following types of studies: load flow, electromechanical transient, electromagnetic transient, short-circuit, reliability. This model shall allow to:

247(a) Assess the behavior of the TNM in steady state conditions;

247(b) Calculate the maximum transmission capacity of the TNM, either by line or for more complex connection links;

247(c) Assess the behavior of the TNM after electromechanical or electromagnetic transients produced by failures or unplanned outages of large generators or transmission lines.

14. ENVIRONMENTAL CONSIDERATIONS

14.1. CRITERIA

Article 248 Each TFO shall implement an environmental management program for the facilities located in its jurisdiction and added to the TNM, allowing for:

248(a) The minimization of the environmental impact originated from the transmission activities and transformation of the electrical energy.

248(b) The permanent pursuit of the indicators to verify the fulfillment of the effective norms of environmental control in each country where the installation is located.

14.2. CONDITIONS

Article 249 The minimum conditions that shall be fulfilled by each TFO with respect to their facilities added to the TNM include:

249(a) Observe the strict fulfillment of the effective environmental legislation in each country where their facilities are located, assuming the responsibility to adopt the measures that correspond to avoid harmful effects to the air, land, water and other components of the ecosystem.

249(b) Perform the maintenance of the main and auxiliary equipment and facilities for transmission and transformation, in conditions that allow smaller or equal levels of contamination than the fixed levels that have been effected by the environmental legislation to each country - nation and / or city that corresponds to each individual case.

249(c) Implement and maintain information systems throughout the operation period to facilitate the verification of the fulfillment of the environmental protection norms.

14.3. REQUIREMENTS

Article 250 Each TFO shall compile the environmental conditions that their facilities and other installations affected by the TNM are subject to, and an evaluation of the present and potential impacts during the expected operation period. This task shall be carried out within one year from the enforcement of this PTOA-GSC. The facilities shall meet environmental requirements according methodologies based on the environmental management manuals of each respective Country.

Article 251 Within the compilation term specified in the previous article, each TFO shall present a report on the measures that should be anticipated for the adjustment of all the facilities, processes and environmental control systems corresponding to the operation of the TNM. This report shall be subject to the approval of the RRB.

Article 252 The TFO shall have the sole responsibility for the economic compensation that may be required as a result of damages caused to the personnel of the same company and/or to third parties in case of environmental requirements are not fulfilled.

Article 253 When in opinion of the competent authority of each Country it is necessary to update and/or to verify the fulfillment of the conditions of the operations related to the control of the contamination, the TFO shall be provided of all of the elements that allow it for the fulfillment of such assignment. The TSO shall make available all the information required from it.

Article 254 Periodic measurements on the levels of the electromagnetic field, radio interference, audible noise and tensions of contact and step, as well as control on the earth connections, in the presumably critical points shall be carried out.

Article 255 During the operation of the TNM, each TFO shall observe the fulfillment of the tolerance levels for electromagnetic field, radio interference, audible noise and tensions of contact and step. They shall follow the effective legislation in each country. In case there is not specific regulation in the country, they shall follow the established international rules corresponding to similar facilities.

Article 256 The TFO shall adapt and/or install systems of containment and recovery of the cooling liquids in the transforming and/or compensating stations so as to avoid the contamination of pluvial and/or health water drainage in case of accidents.

Article 257 The TFO shall use manual and/or mechanical means for pruning activities and in the maintenance of the servitude strips, routes of access and transforming stations. If the use of chemical substances is required, the TFO shall ask for the necessary authorization to the corresponding authority before carrying out any activities.

Article 258 The legislation at the national and/or municipal level shall be observed with respect to permissible levels for noises and vibrations.

Article 259 The norms related to the use, processing, storage and final disposal of equipment that contain toxic or dangerous substances to the health and to the atmosphere shall be observed. The legislation on "Dangerous Wastes" and "Import of Wastes" in each country shall be applied.

Article 260 The norms related to the use, processing and disposal of polychlorinated biphenyls shall be observed. For new facilities, the use of such substances shall be prohibited.

14.4. NON-COMPLIANCE

Article 261 If the TFO does not comply with the measures enumerated in this document within the prescribed terms, it shall receive a warning from the RRB and shall be forced to make the necessary adjustments to fulfill the specific conditions within the term that was established by the RRB.

Article 262 If the established term for the compliance lapses and the TFO still does not comply the measures, the corresponding authority has the power to declare the incapacitation of the installation until the non-compliance case is resolved. The TFO shall be the only entity that is responsible for the corresponding economic damages.

SETTLEMENT CODE

1. CURRENCY

Article 263 All operations of Cross-border Trading ruled by this PTOA-GSC shall be denominated in US Dollars.

2. SETTLEMENT CODE FOR STAGE 1 OF THE PTOA

2.1. OPPORTUNITY CROSS-BORDER TRANSACTIONS

2.1.1. GENERAL ASPECTS

Article 264 The TSOs of different countries shall be able to freely agree Opportunity Cross-Border Transactions for selling and buying energy through international Interconnectors, using the remaining transmission capacity between countries after energy exchanges associated to PPAs are scheduled.

Article 265 Available transmission capacity for Opportunity Cross-Border Transactions shall be reported by the TSOs to the RRB once this institution is operative in order to populate the regional commercial data base, under conditions provided by Article 276 and Article 277

2.1.2. DISPATCH OF OPPORTUNITY CROSS-BORDER TRANSACTIONS

Article 266 Accepted Opportunity Cross-Border Transactions become firm commitments for the parties.

Article 267 Those TSO that agreed to perform an Opportunity Cross-Border Transaction must schedule the corresponding transactions in their respective systems, according to national rules and procedures.

2.1.3. REAL TIME OPERATION

Article 268 During the real-time operation, the TSO of each country shall be responsible to keep in the Cross-border Load Flows associated to the accepted transactions, by adjusting through AGC or manually the internal generation dispatch..

Article 269 The TSO of each country is allowed to modify unilaterally the scheduled cross-border load flows only in case of "force majeur" in its own operated system, unless particular conditions on this are freely agreed between the parties and are were previously reported to the RRB once this institution is operative.

Article 270 In case of "force majeur" the TSO of the affected system shall report the modifications on the scheduling to the TSO of neighboring countries. The TSOs of the countries affected by the change in Cross-border Load Flows shall coordinate the re-scheduling of Cross-border Transactions to minimize the impact of changes.

Article 271 The TSO of each country shall be responsible in rescheduling its respective systems in case of quantities of Cross-border Transactions are not respected by another TSO.

Article 272 During real time operation each TSO shall collect data on load flow injected and withdrawn at the ends of each international Interconnector. The collected data shall be reported in Dispatch Interval to the RRB once this institution is operative in order to populate the regional commercial data base, under conditions provided by Article 276 and Article 277

2.2. SETTLEMENT OF OPPORTUNITY CROSS-BORDER TRANSACTIONS

2.2.1. GENERAL ASPECTS

Article 273 Settlement procedures for Opportunity Cross-Border Transactions shall be freely agreed between TSOs .

2.2.2. PRICES

Article 274 Those TSO that perform an Opportunity Cross-Border Transaction shall be able to freely agree prices and conditions by Dispatch Interval. Prices and conditions agreed shall be reported to the RRB once this institution is operative in order to populate the regional commercial data base, under conditions provided by Article 276 and Article 277

Article 275 Transmission tariff for each Opportunity Cross-Border Transaction shall be freely agreed by the TSOs. Prices and conditions shall be reported to the RRB once this institution is operative in order to populate the regional commercial data base, under conditions provided by Article 276 and Article 277

2.2.3. REGIONAL COMMERCIAL DATA BASE

Article 276 The RRB shall organize, maintain and update the regional commercial data base, which shall be a part of the Regional Data Base, containing at least the following commercial information

276(a) Dispatches PPAs (quantities and nodes) for each Dispatch Interval, forecasted in the day ahead Economic Dispatch and registered during real time operation.

276(b) Cross-Border Load Flows through each International Interconnector forecasted for each Dispatch Interval forecasted in the day ahead Regional Economic Dispatch and registered during real time operation.

276(c) Prices and conditions associated to each performed Opportunity Cross-Border Transaction for each Dispatch Interval

276(d) Prices and conditions agreed on transmission tariffs for each performed Opportunity Cross-Border Transaction.

Article 277 Each TSO shall submit weekly to the RRB all the data described in Article 276 in a Dispatch Interval basis for each day of the last week. Information shall be submitted each Wednesday before 12:00am, containing data for the period comprised between Monday and Sunday of the previous week.

2.2.4. DISPUTES ON SETTLEMENT

Article 278 The TSOs shall use reasonable endeavors to resolve the dispute within thirty (30) Working Days after the Opportunity Cross-Border Transaction under discussion was executed. In case they do not reach an agreement, the RRB shall solve the dispute and its final decision on this matter cannot be appealed.

3. SETTLEMENT CODE FOR STAGE 2 OF THE PTOA

3.1. *DISPATCH OF FLEXIBLE PPA*

Article 279 For those parties that hold a Flexible PPA, the following options to meet their associated commitments are available:

279(a) Self-schedule, or schedule by he national TSO of the committed load curve, in a Dispatch Interval basis. In this case the dispatch of the PPA shall be informed by the respective(s) TSO to the RTC following the procedures set in Title 3.2.1 of this PTOA-GSC.

279(b) Participation in the Regional Economic Dispatch

Article 280 In case of self-scheduling, or scheduling by the TSO of committed energy, the respective TSO shall submit the day before the following data to the RTC:

280(a) International Interconnector to be used, identifying nodes of injection and withdrawal where the agents sell and buy respectively the energy to the PPA.

280(b) Quantities, expressed in [MW] per Dispatch Interval, to be injected and withdrawn in the respective nodes.

280(c) Identification of the interval of validity of the informed transaction;

Article 281 The RTC shall define standard formats for exchange of information related to self-scheduled PPA.

Article 282 Those Parties or Single Buyer that choose option provided by Article 279(a) are allowed to submit to the RTC offers and bids, expressed in Currency/MWh, to increase or reduce the dispatched quantity.

Article 283 Offers and Bids to increase or reduce self-dispatched quantities of PPA shall be submitted daily for the next day in a time basis set by the Dispatch Interval according conditions provided by Article 296 .

Article 284 In case the parties choose to participate in the Regional Economic Dispatch according Article 279(b) , they shall submit Offers and Bids to the RTC according the general procedures provided in this Regulation. Offers and bids shall be presented by the TSO of country where is located the buyer of the energy in the PPA.

3.2. *TRANSMISSION CAPACITY FOR OPPORTUNITY CROSS-BORDER TRANSACTIONS*

3.2.1. AVAILABLE TRANSMISSION CAPACITY OF INTERNAL GRIDS

Article 285 Each TSO shall perform the dispatch of its internal generation and demand, including cross-border PPAs. Using a model of the TNM shall calculate the flows in the lines of its Internal Grid identified as part of the TNM, as well of the cross-border Interconnectors that have been used for PPAs.

Article 286 Each National TSO, after performing the dispatch of its internal generation and demand, shall submit to the RTC

286(a) the scheduled load flows long the Internal Grid for the next day in a time basis set by the Dispatch Interval.

286(b) the available transmission capacity of its Internal Grid for Opportunity Cross-Border Transactions for the next day in a time basis set by the Dispatch Interval.

Article 287 Available transmission capacity of each Internal Grid identified as part of the TNM shall be determined according the methodology described in Annex 2 to the PTOA-GSC.

Article 288 Data described in Article 286 shall be submitted by the TSOs to the RTC daily before 10:00am.

3.2.2. AVAILABLE TRANSMISSION CAPACITY OF THE REGIONAL TRANSMISSION NETWORK

Article 289 The RTC shall use the available transmission capacity of the TNM that was calculated by the OPWG, based on the criteria and procedures set in Chapter 11 of this PTOA-GSC.

Article 290 The model referred in Article 289 has to take into account the fulfillment of Performance Standards provided by this PTOA-GSC

Article 291 Every day the RTC shall set the remaining available capacity of the TNM for Opportunity Cross-border Transactions for the next day in a time basis set by the Dispatch Interval, expressed as the maximum capacity that can be injected or withdrawn at each node of the TNM.

The remaining available capacity is the result of discounting the transmission capacity occupied by the national dispatches from the total available transmission capacity of the TNM (TC) as calculated in Article 289 .

Article 292 Every day the RTC shall inform simultaneously to all the Agents the Remaining Transmission Capacity (RC) for opportunity transactions for each Dispatch Interval of the next day, expressed as the maximum transmission capacity available of each line that belongs to the TNM.

Article 293 Announcement to the Agents of Remaining Transmission Capacity (RC) for the next day shall be done before 11:00AM every day.

3.2.3. STANDARD OFFERS AND BIDS

Article 294 The Agents, through the respective TSO, shall submit daily to the RTC Offers for sale or Bids for buying energy to the Regional Economic Dispatch.

Article 295 Before 12:00am the TSOs shall submit electronically the Bids or Offers to the RTC specifying:

295(a) Quantities, expressed in MW, for each Dispatch Interval of the following day.

295(b) Quantities may be composed of one or more blocks, expressed in MW, each one with an associated price for sell or buy, expressed in Currency/MWh.

295(c) In case of Offers for selling energy with more than one block the associated prices have to be increasing. Price associated to the first block may be zero.

295(d) In case of Bids for buying energy with more than one block the associated prices have to be decreasing.

295(e) Node of the TNM where each block is injected or withdrawn. These nodes have to belong to the own grid of the TSO that submits the bid or the offer.

295(f) The RTC shall provide a procedure and electronic standard forms for submitting bids and offers according what is established in this PTOA-GSC.

3.2.4. BIDS AND OFFERS FOR INCREASING AND REDUCING PPAS DISPATCH

Article 296 Offers to increase or reduce a dispatch of a PPA shall be considered as standards offers according the following conditions:

296(a) Offer to increase: All Offer for increase the self-dispatched power associated to a PPA shall be considered as a standard Offer for selling energy at the node where the selling party of the PPA injects the energy associated to the contract.

296(b) Offer to reduce: All Offer for decrease the self-dispatched power associated to a PPA shall be considered as a standard Bid for buying energy or reducing generation at the node where the selling party of the PPA injects the energy associated to the contract.

3.3. REGIONAL ECONOMIC DISPATCH

3.3.1. GENERAL ASPECTS

Article 297 All Opportunity Cross-Border Transactions shall be result of the Regional Economic Dispatch, which shall be based on the Offers and Bids presented by the Agents for buying or selling energy.

3.3.2. DAY AHEAD REGIONAL ECONOMIC DISPATCH

Article 298 Offers and Bids received by the RTC shall be dispatched ex-ante using an optimization model that maximizes the resulting Social Welfare subject to available transmission capacity on the TNM and security and quality standards. This process is the Day-Ahead Regional Economic Dispatch.

Article 299 Basic specifications of the model to be used to perform the Day-Ahead Regional Economic Dispatch are provided in Annex 2. This model shall allow full representation of the TNM through DC Nodal modeling technique, as it is described in the mentioned Annex 2.

Article 300 At the only effect of application of Article 298 , Social Welfare shall be measured as the difference between the total cost of accepted bids, calculated as the sum of each accepted quantity times its associated price, and the total cost of accepted offers, calculated as the sum of each accepted quantity times its associated price.

Article 301 The result of the day ahead Regional Economic Dispatch shall be informed by the RTC to the respective Agents before 3:00pm.

Article 302 Accepted Offers and Bids as result of day ahead Regional Economic Dispatch become firm commitments for the Agents that submitted them.

Article 303 The Agents whose Offers or Bids were accepted must schedule the corresponding transactions in their respective systems, according to national rules and procedures.

3.3.3. REAL TIME OPERATION

Article 304 During the real-time operation, the TSO of each country shall be responsible to keep in the Cross-border Load Flows associated to the accepted transactions, by adjusting through AGC or manually the internal generation dispatch.

Article 305 The TSO of each country is allowed to modify the scheduled cross-border load flows only in case of "force majeur" in its own operated system. In this case the TSO of the affected system shall report the modifications on the scheduling to the MSC of the RTC and TSO of neighboring countries. The TSOs of the countries affected by the change in Cross-border Load Flows shall coordinate the re-scheduling of the cross-border transactions to minimize the impact of changes.

Article 306 If some of the following conditions arise, the TSOs involved shall require to the MSC of the RTC the coordination of the re-scheduling of Cross-border Transactions:

306(a) The unbalance may or is extending to other countries,

306(b) It is necessary the support of other countries to avoid load curtailments or allow complying with the Performance Standards.

In this case the MCS and TSOs shall follow the procedures set in the Chapters 5 and 7 of the Grid Code.

Article 307 The TSO of each country shall be responsible in rescheduling its respective systems in case of a Cross-border Transaction is not respected by another TSO.

Article 308 During real time operation the RTC shall collect data on load flow injected and withdrawn at the ends of each international Interconnector using the RCMS.

Article 309 Based on this information, the RTC shall compute the actual power delivered or withdrawn at each node of the TNM by each Agent whose Offer or Bid has been accepted for the Regional Economic Dispatch.

3.4. SETTLEMENT OF OPPORTUNITY CROSS-BORDER TRANSACTIONS

3.4.1. GENERAL ASPECTS

Article 310 The RTC shall perform the settlement and payments of Opportunity Cross-Border Transactions based on the accepted Offers and Bids and the actual power delivered and withdrawn by the Agents at each node of the TNM.

Article 311 Settlement and payments of Opportunity Cross-Border Transactions shall be made on a monthly basis.

Article 312 The RTC shall administer a settlement system to calculate the Market settlement amount payable by Agents and to be paid to Agents, and facilitate the billing and payment between Agents under the rules provided by.

3.4.2. RESPONSIBILITIES OF THE RTC

Article 313 The RTC shall do the settlement process for the Opportunity Cross-Border Transactions it administers and Transmission Charges, in accordance with this PTOA-GSC.

3.4.3. COMMERCIAL DATA BASE

Article 314 The RTC shall organize, maintain and update a commercial data base containing at least the following commercial information

314(a) Average Price (APP) for each Dispatch Interval forecasted on the day ahead Regional Economic Dispatch and registered during real time operation.

314(b) Total Collection Surplus (TCS) for each Dispatch Interval forecasted on the day ahead Regional Economic Dispatch and registered during real time operation.

314(c) Total Maximum Collection Surplus (TMCS) for each Dispatch Interval forecasted on the day ahead Regional Economic Dispatch and registered during real time operation.

314(d) Self-dispatched Flexible PPAs (quantities and nodes) for each Dispatch Interval submitted for the day ahead Regional Economic Dispatch.

314(e) Actual dispatch of Flexible PPAs (quantities and nodes) for each Dispatch Interval registered during real time operation.

314(f) Bids and Offers (quantities, nodes and prices per block) submitted by each Agent for each Dispatch Interval to participate in Opportunity Cross-Border Transactions.

314(g) Accepted Bids and Offers (quantities, nodes and prices per block) for each Dispatch Interval.

314(h) Injections and withdrawals of power at each node of the TNM and Cross-Border Load Flows through each International Interconnector forecasted for each Dispatch Interval on the day ahead Regional Economic Dispatch

314(i) Actual injections and withdrawals of power at each node of the TNM and actual Cross-Border Load Flows through each International Interconnector forecasted for each Dispatch Interval registered during real time operation.

3.4.4. ECONOMICAL PARAMETERS

Article 315 Economical parameters to be used for settlement of Regional Economic Dispatch are the following:

315(a) Quantity Deviations (QD)

315(b) Average Price (APP)

315(c) Total Collection Surplus (TCS)

315(d) Total Maximum Collection Surplus (TMCS)

Article 316 Quantity Deviations (QD): Once the real time operation of each day is finished, the RTC shall calculate, for each Agent and Dispatch Interval, the algebraic difference expressed in [MW] between the accepted Offers and Bids as resulted of day ahead Regional Dispatch process, and the actual injections and withdrawals that resulted in the real time operation calculated as provided in Article 309 of this PTOA-GSC.

Article 317 Average Price (APP): It is the average price expressed in Currency/MWh of all accepted Offers and Bids, discriminated by block if more than one, weighted by the associated quantities. Offers and Bids penalized according what it is regulated in Sub-title 3.4.6 shall not be included in the calculation of APP. For each Dispatch Interval it is calculated according the following formula:

$$APP = \frac{\sum_{b,j} BP_{jb} \times V_{jb} + \sum_{o,j} OP_{jo} \times V_{jo}}{\sum_{b,j} V_{jb} + \sum_{o,j} V_{jo}}$$

Where:

$V_{jb} =$	Actual quantity withdrawn, expressed in MW, of accepted 'block j' of Bid submitted by 'Agent b'
$BP_{jb} =$	Associated price of accepted 'block j' of Bid submitted by 'Agent b'
$V_{jo} =$	Actual quantity injected, expressed in MW, of accepted 'block j' of Offer submitted by 'Agent o'
$OP_{jo} =$	Associated price of accepted 'block j' of Offer submitted by 'Agent o'

Article 318 Total Collection Surplus (TCS): It is the amount expressed in Currency resulting from the difference between the total cost of accepted bids, calculated as the sum of each accepted quantity times its associated price, and the total cost of accepted offers, calculated as the sum of each accepted quantity times its associated price. Offers and Bids penalized according what it is regulated in Sub-title 3.4.6 shall not be included in the calculation of TCS. For each Dispatch Interval it is calculated according the following formula:

$$TCS = \sum_{b,j} BP_{jb} \times V_{jb} - \sum_{o,j} OP_{jo} \times V_{jo}$$

Where:

V_{jb} =	Actual quantity withdrawn, expressed in MW, of accepted 'block j' of Bid submitted by 'Agent b'
BP_{jb} =	Associated price of accepted 'block j' of Bid submitted by 'Agent b', corrected by the cost of marginal transmission losses associated to the accepted bid
V_{jo} =	Actual quantity injected, expressed in MW, of accepted 'block j' of Offer submitted by 'Agent o'
OP_{jo} =	Associated price of accepted 'block j' of Offer submitted by 'Agent o', corrected by the cost of marginal transmission losses associated to the accepted offer

Article 319 Total Maximum Collection Surplus (TMCS): It is the amount expressed in Currency resulting from the difference between the total cost of accepted bids whose price is higher or equal to APP, calculated as the sum of each accepted quantity times its associated price, and the total cost of accepted offers whose price is lower or equal than APP, calculated as the sum of each accepted quantity times its associated price. Offers and Bids penalized according what it is regulated in Sub-title 3.4.6 shall not be included in the calculation of TCS. For each Dispatch Interval it is calculated according the following formula:

$$TMCS = \sum_{b,j,BP \geq APP} BP_{jb} \times V_{jb} - \sum_{o,j,OP \leq APP} OP_{jo} \times V_{jo}$$

Where:

V_{jb} =	Actual quantity withdrawn, expressed in MW, of accepted 'block j' of Bid submitted by 'Agent b'
BP_{jb} =	Associated price of accepted 'block j' of Bid submitted by 'Agent b', corrected by the cost of marginal transmission losses associated to the accepted bid
V_{jo} =	Actual quantity injected, expressed in MW, of accepted 'block j' of Offer submitted by 'Agent o'
OP_{jo} =	Associated price of accepted 'block j' of Offer submitted by 'Agent o', corrected by the cost of marginal transmission losses associated to the accepted offer

3.4.5. Payments

Article 320 Payments to sellers (PY): monthly payment to agents whose Offers were accepted shall be computed as follows:

$$PY_o = \sum_i T_i \times \sum_j \left\{ OP_{joi} \times V_{joi} + \frac{TCS_i}{TMCS_i} \times MAX\left[\left(APP_i - OP_{joi} \right), 0 \right] \times V_{joi} \right\} - AC_o$$

Where:

PY_o = Monthly payment to 'Agent o'

V_{joi} = Quantity, expressed in MW, of accepted 'block j' of Offer submitted by 'Agent o' in the 'Dispatch Interval i'

OP_{joi} = Associated price of accepted 'block j' of Offer submitted by 'Agent o' in the 'Dispatch Interval i', corrected by the cost of marginal transmission losses associated to the accepted Offer

APP_i = Average Price in the 'Dispatch Interval i'

TCS_i = Total Collection Surplus in the 'Dispatch Interval i'

$TMCS_i$ = Total Maximum Collection Surplus in the 'Dispatch Interval i'

T_i = Duration of 'Dispatch Interval i', expressed in Hours

AC_o = Additional Charges to 'Agent o', as provided in Article 322

$i = 1,...,I$ where I is the total number of Dispatch Intervals within the month.

Article 321 Payments by buyers (PYb): monthly payment to agents whose Bids were accepted shall be computed as follows:

$$PY_b = \sum_i T_i \times \sum_j \left\{ BP_{jbi} \times V_{jbi} + \frac{TCS_i}{TMCS_i} \times MAX\left[\left(BP_{jbi} - APP_i \right), 0 \right] \times V_{jbi} \right\} - AC_b$$

Where:

PY_b = Monthly charge to 'Agent b'

V_{jbi} = Quantity, expressed in MW, of accepted 'block j' of Bid submitted by 'Agent b' in the 'Dispatch Interval i'

BP_{jbi} = Associated price of accepted 'block j' of Bid submitted by 'Agent b' in the 'Dispatch Interval i', corrected by the cost of marginal transmission losses associated to the accepted Bid

APP_i = Average Price in the 'Dispatch Interval i'

TCS_i = Total Collection Surplus in the 'Dispatch Interval i'

T_i = Duration of 'Dispatch Interval i', expressed in Hours

AC_b = Additional Charges to 'Agent b', as provided in Article 322

$i = 1,...,I$ where I is the total number of Dispatch Intervals within the month.

Article 322 Additional Charges (AC): The RTC shall discount or add to the monthly invoices the payments that each agent must make for:

322(a) Transmission tariffs, as provided in Chapter 12 of the Grid Code.

322(b) Functioning of the regional institutions (if this funding source were implemented)

3.4.6. PENALTIES

Article 323 Quantity Deviations of buyers: If power withdrawn at a given node is lower than the scheduled and the TSO is responsible of this deviation, the absolute value of QD shall be considered as the quantity of an accepted Offer in the day ahead Regional Economic Dispatch for settlement purposes and shall be paid to the responsible TSO at the lowest Offer price accepted at the involved node in the Regional Economic Dispatch reduced according the Penalty Factor set in Article 1 . If power withdrawn at a given node is higher than the scheduled and the TSO is responsible of this deviation, the absolute value of QD shall be considered as the quantity of an accepted Bid at the involved node in the day ahead Regional Economic Dispatch for settlement purposes and shall be paid by the responsible TSO at the highest Bid price accepted in the Regional Economic Dispatch increased according the Penalty Factor set in Article 1 .

Article 324 Quantity Deviations of sellers: If power injected at a given node is lower than the scheduled and the TSO is responsible of this deviation,, the absolute value of QD shall be considered as the quantity of an accepted Bid in the day ahead Regional Economic Dispatch for settlement purposes and shall be paid by the responsible TSO at the highest Bid price accepted at the involved node in the Regional Economic Dispatch increased according the Penalty Factor set in Article 1 . If power injected at a given node is higher than the scheduled and the TSO is responsible of this deviation, the absolute value of QD shall be considered as the quantity of an accepted Offer in the day ahead Regional Economic Dispatch for settlement purposes and shall be paid to the responsible TSO at the lowest Offer price accepted at the involved node in the Regional Economic Dispatch reduced according the Penalty Factor set in Article 1 .

Article 325 The money collected as result of what it is regulated in Article 323 and Article 324 shall be used for compensate to those Agents whose real dispatches were different from the scheduled in the day ahead Regional Economic Dispatch and were not responsible for such deviations.

3.4.7. SETTLEMENT DOCUMENT

Article 326 The RTC shall issue a Preliminary Settlement Document, which shall include at least the following information:

326(a) The description of the settlement for the Opportunity Cross-Border Transactions and the Other Charges for the previous month;

326(b) The Opportunity Cross-Border Transactions settlement amount of the month;

326(c) The energy quantities for the PPAs and Opportunity Cross-Border Transactions where the Agent is a party, and

326(d) Sufficient supporting data to enable each Agent for auditing the settlement calculation.

Article 327 Not later than five (5) Working Days after the beginning of each month, the RTC shall send, preferably through electronic mail or any other quicker and cost-effective means, to each Agent the Preliminary Settlement Document, which sets out the Opportunity Cross-Border Transactions of that Agent in the month and the settlement amount payable by or to that Agent.

Article 328 If an Agent reasonably believes there is an error or discrepancy in the Preliminary Settlement Document, the Agent shall notify the RTC within ten (10) Working Days of receiving the Preliminary Settlement Document.

Article 329 If the RTC receives a complaint of an error or discrepancy, the RTC shall review the Preliminary Settlement Document. If the RTC considers that the complain is correct and that the Preliminary Settlement Document contains an error or discrepancy, the RTC shall notify all Agent whose final statements shall be affected within five (5) Working Days of the date on which the error or discrepancy first came to the attention of the RTC. The RTC shall correct the error or discrepancy in the Final Settlement Document.

Article 330 Not later than twenty (20) Working Days after the beginning of each month, the RTC shall send to each Agent the Final Settlement Document, which sets out the Opportunity Cross-Border Transactions of that Agent in the month and the settlement amount payable by or to that Agent.

Article 331 The Final Settlement Document shall include the same type of information as the Preliminary Settlement Document, in particular sufficient supporting data to enable each Agent to audit the calculation of the amount payable by or to that Agent.

Article 332 The RTC shall draft a Settlement Market Procedure with the timetable and mechanisms to exchange settlement information and complaints.

3.4.8. INVOICING

Article 333 With the Final Settlement Document, the RTC shall issue within 22 Working Days of each month,

333(a) The invoice for the previous month to each Agent that has a negative settlement amount, indicating the amount that the Agent shall pay. This amount shall be coincident with the results shown in the Final Settlement Document, which at the same time will act as a description of the detailed calculation.

333(b) A letter of credit for the previous month to each Agent with a positive settlement amount, indicating the amount that the Agent shall be paid. This amount shall be coincident with the results shown in the Final Settlement Document, which at the same time will act as a description of the details of calculations.

Article 334 The RTC shall act in this process representing the Agents, but without assuming payment responsibilities. Debts and credits remain as rights and obligations of the Agents and the RTC is not liable for non-payments of Agents.

Article 335 The RTC shall issue a Letter of Credit for itself, indicating the total due as RTC.

3.4.9. PAYMENT SYSTEM

Article 336 The payment system shall be through escrow accounts administered by a Bank assigned this responsibility, for the purposes of facilitating settlements and the collection and payment of the Opportunity Cross-Border Transactions settlement.

Article 337 Each Agent shall have an account in the Bank assigned the administration of the payment system. Each Agent shall inform the RTC the name and number of this account as a condition to register and be authorized as an Agent.

Article 338 The RTC shall also have an account in the same Bank, to deposit the payments of Agents to cover the approved cost.

Article 339 The RTC shall send to the Bank responsible for the administration of the payment system, a summary of the Final Settlement Document identifying for each Agent:

339(a) If the Agent has a payment is due and the amount due; or

339(b) If the Agent has a credit and the proportionality factor with which the Bank shall assign to that Agent the payments received in the Common escrow account.

Article 340 Where in the Final Settlement Document the settlement amount for a Agent is a negative amount and that Agent receives an invoice, no later than 2.00 p.m. on five (5) Working Days after receiving the invoice, the Agent shall deposit in the Common escrow account the settlement amount stated to be payable in the Final Settlement Document, whether or not the Agent disputes or continues to dispute the amount payable.

Article 341 Where the settlement amount for an Agent is a positive amount and the Agent receives a letter of credit, upon a payment to the Common escrow account, the Bank shall transfer the payment according to the proportionality factor included in the Final Settlement Document.

Article 342 The Bank shall notify the RTC the payments made and Agents that did not pay totally or partially the settlement amount due.

Article 343 Upon notification from the Bank of a non-payment, the RTC shall instruct the Agent to comply with the payment obligations not later than the next Working Day. If after this deadline, the Agent still has not made a deposit to cover the full settlement amount due, the RTC shall make a claim of the security deposit for any outstanding payment and inform the RRB.

Article 344 An Agent shall pay interests on any unpaid settlement amount due and payable under the rules established by this PTOA-GSC. The RRB shall set the rate of interest payable.

TRANSITORY MEASURES

Article 345 During the Stage 1 of the PTOA the following measures shall be enforced:

345(a) The Technical Secretariat, then RRB, once put in place, shall organize the preliminarily Regional Database, record transactions and collect regional information as ruled in the title “2 - Regional Database” of the Grid Code section.

345(b) Countries shall use Transmission Standards for design of cross-border Interconnectors and for scheduling country to country transactions as ruled in the title “3 - Transmission Standards” of the Grid Code section.

345(c) The transmission capacity of interconnectors used for country to country trading shall be calculated by the OPWG as ruled in the title “11 - Calculation of the transmission capacity” of the Grid Code section.

345(d) The SPWG shall start planning activities as ruled in the title “13 - Regional Transmission Planning” of the Grid Code section as soon as it is put in place.

Article 346 Prior to starting of Stage 2, all the sections of the Grid Code shall be enforced:

Article 347 During the Stage 1 of the PTOA, the articles grouped under the following titles of the Settlement Code shall be enforced:

347(a) “1 - Currency”

347(b) “2 - Settlement code for Stage 1 of the PTOA”

Article 348 Prior to starting of Stage 2 of the PTOA, the articles grouped under the following titles of The Settlement Code section shall be enforced:

348(a) “1 - Currency”

348(b) “3 - Settlement code for Stage 2 of the PTOA”

ANNEX 1
IDENTIFICATION OF THE TRADING NETWORK MODEL

1. FIRST STEP: DEFINITION OF THE BASIC TNM

The nodes to include in the basic TNM are:

- The nodes and lines that comprise the existing Inter-connections higher than 100 KV level;
- The nodes and lines of the predicted expansions.

When a new Interconnector enters the system, the nodes of such interconnection and the Interconnector itself will be part of the basic TNM

Moreover, the nodes and lines of the planned expansions would be part of the TNM.

2. SECOND STEP: IDENTIFICATION OF THE CONTROL NODES

The control nodes in each national electrical system are the nodes that are nearest electrically to the terminal node of an interconnection (without including it) where the national TSO can make offers for Cross-border Trading—i.e. where the TSO can control the injection/retirement of energy independent from the other nodes.

These nodes correspond to the nodes where a generator or an area of the system that consists of a set of generators and loads, and are connected in radial form to the TNM. When there is demand with a verified capacity to control their consumption, the nodes where these ones are interconnected to the TNM shall be incorporated to this category.

The control nodes shall be limited to the higher voltage levels in each Country (example 230 and 138kV, or 230 and 115kV).

The identification of the control nodes shall be made while examining the location topology of the generators and the points where the TSO can make controllable offers for Cross-border opportunity trading.

3. THIRD STEP: IDENTIFICATION OF THE PRELIMINARY TNM

The preliminary TNM is the set formed by all of the nodes and lines that have been defined in the previous steps, and the lines and nodes that unite them by means of the shorter electrical route (smaller impedance) at each level of voltage. The preliminary TNM must be continuously tied to all of the Countries. If this continuity is not possible, many transitory TNM's shall be defined to serve as the networks that are necessary to tie all of the countries.

In order to connect the control nodes to the basic network, a control node that is closer to the basic network will be selected. Initially, the nodes of the interconnection are the limits of the basic network, but as connections are added starting from the control nodes, the basic network will be expanded over these new connections.

The process to follow for the identification of the preliminary TNM in each country is as follows:

- C-1. The higher level of tension in the basic TNM is selected.
- C-2. Then looking for the nearest electrical connection between some control node and a node of the basic TNM.
- C-3. If the connection cannot be obtained at the same tension level, the shorter electrical route through a transforming substation will be used.
- C-4. If the control nodes to be connected have not been exhausted, the process came back to step "C-2"
- C-5. The tension level immediately lower (where control nodes exist) is selected and then goes to the step "C-2"

4. FOURTH STEP: IDENTIFICATION OF THE BACK-UP LINES FOR THE PRELIMINARY TNM

Additional elements to the preliminary TNM for several scenarios shall be identified, according to a criterion that shall consider two factors: (1) the magnitude of the change of flow by the elements before and after simulating one balanced import and export (of a power PIE) between pairs of located virtual nodes in each Interconnection at the point where enters to the Country in analysis and; (2) the relation of this change with the value PIE

Simulations with the load flow software that uses the RTC shall be performed for n scenes in the country in analysis. The flows in the transmission lines of the Country of analysis in the situation are compared with and without the PIE transaction and it is decided to add to the TNM of this element if it is fulfilled the following criteria:

- Let *Fak* and *Fck* the flow the line in the case without the PIE transaction and in the case with this transaction respectively and in scene *k* in an element *l* that have not been selected in the passages To and C.
- Let *Ek* the absolute value of the net export and *Tk* the amount of transit for scene k in the country where is the analyzed element
- Element *l* is included in the TNM if, n/N > P%, where:
    - n= *number of scenarios where is fulfilled that.* |Fck–Fak| / Fak*100>U%
    - N= *Total number of scenarios analyzed*
- *For the determination of the initial TNM the used values will be:* U%=10% and P%=10% *;*
- *The RRB can modify the values of U% and P%.*

5. FIFTH STEP: VERIFICATION BY THE TSO

The RTC in coordination with the TSO, based on regional studies of operative security, can add elements to those identified in steps one to four when these are necessary for support the regional quality and security. This studies shall consider mainly the effect of lines although are not part on the TNM, are connected in parallel, and consequently their outages may affect the flows in the TNM.

ANNEX 2
REGIONAL ECONOMIC DISPATCH: MODEL SPECIFICATIONS

1. STATEMENT OF INDEXES AND VARIABLES

The following variables and indexes shall be used to state the model

p : denotes a GMS country

Np: total number of nodes in the part of the TNM located within country p. A 'border node' should be included, modeled as a virtual node located at the point where each Interconnector crosses the border. The swing node shall be denoted with number 'zero'.

Lp: total number of lines in the part of the TNM located within the country p. A virtual line between the 'border node' and the real internal node where the cross-border line ends shall be included in the model.

LC: total number of contingencies used for the security-constrained economic dispatch,

d_{kp}: denotes the demand at node k of country p, $k=0,\dots Np-1 \;\forall p$

$\boldsymbol{d}$ denotes the dispatched demand vector of country p, whose elements are d_{kp}

$\boldsymbol{d_{cp}}$ denotes the vector of dispatched demand for Opportunity Cross-border Transactions at each node kp of country p, whose elements are $d_{c\,p\,kp}g_{mp}$: denotes the generation at node m of country p, $m=0,\dots Np-1 \;\forall p$

$\boldsymbol{g}$ denotes the dispatched generation vector of country p, whose elements are g_{mp}

$\boldsymbol{g_{cp}}$ denotes the vector of dispatched generation for Opportunity Cross-border Transactions at each node of country p, whose elements are $g_{c\,p\,mp}$

z_{lp} : denotes the load flow along the line l of country p. $l = 1,,,,Lp \;\forall p$

Z_{lp}^{-}, Z_{lp}^{+} : denote the maximum load flow allowed in normal operation condition through line l that connects node i with node j of country p, when load flow goes from j to i, and from i to j respectively.

ZE_{lp}^{-}, ZE_{lp}^{+} : denote the maximum load flow allowed in emergency operation condition through line l that connects node i with node j of country p, when load flow goes from j to i, and from i to j respectively.

y_{lp}: series susceptance of line l of country p, i.e the inverse of series reactance of line l.

$\boldsymbol{A}$ = the L x (N-1) 'network incidence matrix' with elements 0, 1 or -1 corresponding to the network interconnections. If link l originates at node i and terminates at node j, then:

$a_{li} = 1$

$a_{lj} = -1$

$a_{ls} = 0 \ (s \neq i, j)$

For the swing node it is assumed that:

i = 0, and the corresponding column is not included in matrix ***A***

$\delta_i = 0$

Ω = L x L matrix with diagonal elements equal to y_l

H: 'Power transference shift factors matrix', which is calculated based on matrixes ***A*** and ***Ω***, as follows:

$$\boldsymbol{H = \Omega \times A (A^t \times \Omega \times A)^{-1}}$$

$\boldsymbol{H_j}$: the matrix ***H*** under contingency j, which is defined as the outage of one or more lines simultaneously.

Hc: It is the reduced version of matrix ***H***, which considers only those nodes where withdrawals or injections to the TNM for Opportunity Cross-border Transactions are done

kp: the nodes of country p where the corresponding TSO presents Bids

mp: the nodes of country p where the corresponding TSO presents Offers

UKP: number of Bids presented by TSO of country p at node kp

UMP: number of Offers presented by TSO of country p at node mp $G_{p\ u\ mp}$:block u of generation offered by country p at node mp, (u=1,,,,UMP)

$g_{p\ u\ mp}$: generation dispatched of block u offered by country p at node kp, (u=1,,,, UMP)

$cv_{p\ u\ mp}$: price offered of country p for the block of generation designated $G_{p\ u\ mp}$

UMP: number of bids presented by TSO of country p in node kp

$D_{p\ u\ kp}$: block u of demand bided by country p at node kp, (u=1,,,, UKP)

$d_{p\ u\ kp}$: demand dispatched of block u, offered by country p at node kp, (u=1,,,, UKP)

$pv_{p\ u\ kp}$:Bid of country p for the block of demand designated $D_{p\ u\ kp,}$ (u=1,,,, UKP)

q: number of cross-border Interconnectors that link countries qp1 and qp2. Load flow is assumed from qp1 to qp2. q= 1,,,,Q

nqp1: number of node of country qp1 that is assigned to the connection q. For this node UKP=UMP=1

nqp2: number of node of country qp2 that is assigned to the connection q. For this node UKP=UMP=1

$\Gamma_{kp:}$: is the number of Bids or offers that the TSO presents in node kp

$\Gamma_{mp:}$: is the number of Offers or offers that the TSO presents in node mp

z_{lp}*: load flow in line l of country p, which results from the internal dispatch.

g: vector (N-1) x 1, of elements g_m. Swing node is not considered

d: vector (N-1) x 1 of components d_k. Swing node is not considered

$\boldsymbol{z}$: vector L x 1 composed by elements z_l

$\boldsymbol{Z}^-$: vector L x 1 composed by elements Z_l^-

$\boldsymbol{Z}^+$: vector L x 1 composed by elements Z_l^+

$B_{kp}(d_{kp})$: the demand benefit at node kp associated at the level of consume d_{kp}, expressed as follows:

$$B_{kp}(d_{kp}) = \sum_u pv_{u\,kp}\, d_{u\,kp} \qquad u = 1,\dots \Gamma_{kp} \tag{1}$$

$C_{mp}(g_{mp})$: the variable cost function of generator at node mp, expressed as follows:

$$C_{mp}(g_{mp}) = \sum_u cv_{u\,mp}\, g_{u\,mp} \qquad u= 1,\dots \Gamma_{mp} \tag{2}$$

Based on previous definitions, the following conditions must be satisfied:

Total dispatched demand at node kp (d_{kp}):

$$d_{kp}= \sum_u d_{u\,kp} \qquad \forall\, u = 1,\dots \Gamma_{kp} \tag{3}$$

$$\text{with} \quad d_{u\,kp} \le D_{u\,kp} \qquad \forall\, u = 1,\dots \Gamma_{kp} \tag{4}$$

Total dispatched generation at node mp (g_{mp}):

$$g_{mp}= \sum_u g_{u\,mp} \qquad \forall\, u = 1,\dots \Gamma_{mp} \tag{5}$$

$$\text{with} \quad g_{u\,mp} \le G_{u\,mp} \qquad \forall\, u = 1,\dots \Gamma_{mp} \tag{6}$$

All equations included in this Annex which terms are expressed in MW need to be multiplied by the Dispatch Interval duration as defined in this PTOA-GSC.

2. ECONOMIC DISPATCH FOR EACH COUNTRY MODELLING

The Economic Dispatch problem for a country p can be stated as:

$$\text{Maximize } W = \sum_{kp} B_{kp}(d_{kp}) - \sum_{mp} C_{mp}(g_{mp}) \tag{7}$$

Subject to

$$\sum_{pk} d_k - \sum_{mp} g_{mp} - \text{Losses} = 0 \qquad pk=1\dots,Np; \quad mp=1,\dots,Np \tag{8}$$

$$\boldsymbol{Z}^- \le \boldsymbol{H} \times [\, \boldsymbol{d} - \boldsymbol{g} \,] = \boldsymbol{z} \le \boldsymbol{Z}^+ \tag{9}$$

$$\boldsymbol{ZE}^- \le \boldsymbol{H_{pj}} \times [\, \boldsymbol{d} - \boldsymbol{g} \,] = \boldsymbol{z} \le \boldsymbol{ZE}^+ \qquad j = 1,\dots, LC \tag{10}$$

Equation (35) states the mathematical expressions for ‘Losses’ calculation according a linear approximation.

Equations (1)-(10) and (35) constitute a set of linear equations that define the country’s economic dispatch. Optimization can be achieved using linear programming techniques.

Let the results of the national dispatch of country 'p' be $\boldsymbol{g_p}^*$, $\boldsymbol{d_p}^*$, $\boldsymbol{z_p}^*$. As result of the dispatch process, the generation $\boldsymbol{g_p}^*$ and demand $\boldsymbol{d_p}^*$ produce the load flows $\boldsymbol{z_p}^*$.

Once the national dispatch was performed, the resulting available capacity of the transmission system for Opportunity Cross-border Transactions, measured as withdrawals and injection at each node $\boldsymbol{d_c}$ and $\boldsymbol{g_c}$, is defined by the following equation:

$$\boldsymbol{Z_p}^- - \boldsymbol{z_p}^* \le \boldsymbol{Hc_p} \times [\, \boldsymbol{d}_{\mathrm{c}} - \boldsymbol{g}_{\mathrm{c}}] = \boldsymbol{z} \le \boldsymbol{Z_p}^+ - \boldsymbol{z_p}^* \qquad (11)$$

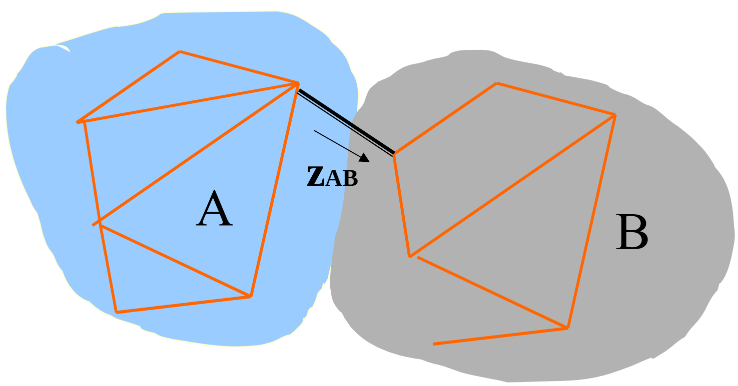
where the vectors $[\boldsymbol{Z_p}^- - \boldsymbol{z_p}^*]$ and $[\boldsymbol{Z_p}^+ - \boldsymbol{z_p}^*]$ represent the transmission capacity that can flow through both the internal transmission system of the country , and the remaining transmission capacity of the cross-border lines. $\boldsymbol{Hc}$ is now the reduced 'Power transference shift factors matrix', which only takes into consideration those nodes where Bids or Offers for Opportunity Cross-border Transactions were done.

Countries can use a different methodologies for their internal dispatch, but they have to inform to the RTC the values of $\boldsymbol{z_p}^*$.

3. REGIONAL ECONOMIC DISPATCH FOR TWO COUNTRIES

The formulas used to pose the equations for the two-countries dispatch are based on the following graphic scheme.

Basic scheme for two countries and one international Interconnector



In this case p = A for Country A, and p = B for country B. The two countries dispatch problem can now be stated as:

$$\text{Maximize } W = \sum_{kA} B_{kA}(d_{c\,A\,kA}) + \sum_{kB} B_{kB}(d_{c\,B\,kB}) - \sum_{mA} C_{mA}(g_{c\,B\,mA}) - \sum_{mB} C_{m}(g_{c\,B\,mB}) \qquad (12)$$

Subject to:

$$\sum_{kA} d_{cAkA} + \sum_{kB} d_{cBkB} - \sum_{mA} g_{cBmA} - \sum_{mB} g_{cBmB} - \text{Losses} = 0 \qquad (13)$$

$$\boldsymbol{Z_A}^- - \boldsymbol{z_A}^* \le \boldsymbol{Hc_A} \times [\, \boldsymbol{d}_{\mathrm{cA}} - \boldsymbol{g}_{\mathrm{cA}}] = \boldsymbol{z} \le \boldsymbol{Z_A}^+ - \boldsymbol{z_A}^* \qquad (14)$$

$$\boldsymbol{Z_B}^- - \boldsymbol{z_B}^* \le \boldsymbol{Hc_B} \times [\, \boldsymbol{d}_{\mathrm{cB}} - \boldsymbol{g}_{\mathrm{cB}}] = \boldsymbol{z} \le \boldsymbol{Z_B}^+ - \boldsymbol{z_B}^* \qquad (15)$$

$$\boldsymbol{d}_{\mathrm{cA1}} - \boldsymbol{g}_{\mathrm{cA1}} = - \boldsymbol{d}_{\mathrm{cB1}} + \boldsymbol{g}_{\mathrm{cB1}} \qquad (16)$$

Where:

$k_{A:}$ denotes the nodes of country A,

k_B denotes the nodes of country B,

'1' denotes the node at the border between A and B

Sums are extended to all the nodes of each country, swing nodes inclusive.

Equation (35) states the mathematical expressions for 'Losses' calculation according a linear approximation.

Sets of equations (1)-(6), (12)-(16) and (35) state the mathematical formulation that allows to optimize the joint dispatch of countries A and B, after they performed their respective internal dispatches.

This methodology shall be used for country-to-country dispatch during stage #1. The linear problem can be solved using linear programming.

4. REGIONAL ECONOMIC DISPATCH AMONG MORE THAN TWO COUNTRIES

During stage #2, each country shall function as one or more control areas, and shall be able to control the Cross-border Load Flows through AGC or manually.

The Regional Economic Dispatch can now be stated as:

$$\text{Maximize } W = \sum_p \sum_{kp} \sum_u cv_{c\,p\,u\,kp}\, g_{c\,p\,u\,kp} - \sum_p \sum_{kp} \sum_u pv_{p\,u\,kp}\, d_{c\,p\,u\,kp} \quad (17)$$

Subject to

$$g_{c\,p\,u\,kp} \leq G_{c\,p\,u\,kp} \quad (18)$$

$$d_{c\,p\,uk\,p} \leq D_{c\,p\,u\,kp} \quad (19)$$

$$\sum_p \sum_{kp} \sum_u g_{c\,p\,u\,kp} - \sum_p \sum_{kp} \sum_u d_{c\,p\,u\,kp} - \text{Losses} = 0 \quad (20)$$

$$\boldsymbol{Z_p}^- - \boldsymbol{z_p}^* \leq \boldsymbol{Hc_p} \times [\, \boldsymbol{d}_{cp} - \boldsymbol{g}_{cp} \,] = \boldsymbol{z} \leq \boldsymbol{Z_p}^+ - \boldsymbol{z_p}^* \qquad p=1,\ldots,6 \quad (21)$$

$$d_{c\,pa\,1\,nqp1} - g_{c\,pa\,1\,nqp1} = - d_{c\,pb\,1\,nqp2} + g_{c\,pb\,1\,nqp2} \qquad q=1,\ldots,Q \;\; (pa, pb = 1,\ldots,6) \quad (22)$$

Equation (35) states the mathematical expressions for 'Losses' calculation according a linear approximation.

Set of equations (17)-(22) and (35) states the mathematical formulation of the Regional Economic Dispatch. This problem shall be solved using linear programming and shall be solved every for each Dispatch Interval of the next day. The results are the Day-Ahead Regional Economic Dispatch. Values of $g_{p\,u\,kp}$ and d_{pukp} must be scheduled by the TSO of country p.

To reduce the size of the problem, only the nodes of matrixes $\boldsymbol{H_p}$, where each country presents bids-offers, were considered.

$\boldsymbol{H_p}$ matrixes and the available capacities of lines, $\boldsymbol{Z_p}^- - \boldsymbol{z_p}^*$ and $\boldsymbol{Z_p}^+ - \boldsymbol{z_p}^*$, shall be daily submitted by TSOs to the RTC.

Equation (22) is valid only if load flows through cross-border Interconnectors can be individually controlled. If the AGC only control total cross-border flows, these load flows become not independent, and equations (21) and (22) are not valid.

5. REGIONAL ECONOMIC DISPATCH – GENERAL CASE

The general formulation of the Regional Economic Dispatch is as follows:

$$\text{Maximize } W = \sum_p \sum_{kp} \sum_u cv_{p\,u\,kp}\, g_{p\,u\,kp} - \sum_p \sum_{kp} \sum_u pv_{p\,uk\,p}\, d_{p\,uk\,p} \qquad (23)$$

Subject to

$$g_{p\,u\,kp} \leq G_{p\,u\,kp} \qquad (24)$$

$$d_{p\,u\,kp} \leq D_{p\,u\,kp} \qquad (25)$$

$$\sum_p \sum_{kp} \sum_u g_{p\,u\,kp} - \sum_p \sum_{kp} \sum_u d_{p\,u\,kp} - \text{Losses} = 0 \qquad (26)$$

$$\boldsymbol{Z_p}^{-} - \boldsymbol{z_p}^{*} \leq \boldsymbol{H_p} \times [\, \boldsymbol{d}_p - \boldsymbol{g}_p \,] = \boldsymbol{z} \leq \boldsymbol{Z_p}^{+} - \boldsymbol{z_p}^{*} \qquad p=1,\ldots,6 \qquad (27)$$

Equation (35) states the mathematical expressions for 'Losses' calculation according a linear approximation.

Equations (23)-(27) and (35) state the mathematical formulation of the regional economic dispatch. This problem can be solved using linear programming.

6. CONSIDERATIONS ON MATRIX H

Matrixes ***H*** and matrix ***Hp*** shall consider the Performance Standards.

The OPWG shall identify each year:

1. The set of possible contingencies (loss of a line or major facility) that will be considered for the day ahead Regional Economic Dispatch.
2. The emergency limits of each line or major facility

The dispatch must ensure that the TNM would remain operative within security limits if any of the identified contingencies occurs. To accomplish the criteria set in the performance standards, the modelled loss of the facility must leave the remaining elements of the system operative.

Each contingency state j shall be characterized for the topology of the TNM assuming a line of major facility unavailable, and the emergency limits of each line.

Let:

$\boldsymbol{H_j}$: matrix ***H*** of the transmission system when the contingency j occurs

$\boldsymbol{ZE}^{-}$; $\boldsymbol{ZE}^{+}$: vector of maximum load flows allowed in each line during emergencies.

Therefore the security-constrained economic dispatch is stated as follows:

$$\text{Maximize } W = \textstyle\sum_k B_k(d_k) - \sum_m C_m(g_m) \tag{28}$$

Subject to

$$\textstyle\sum_k d_k - \sum_m g_m - \text{Losses} = 0 \qquad k=1,\ldots,N \;;\; m=1,\ldots,N \tag{29}$$

$$\boldsymbol{Z^-} \le \boldsymbol{H}\,[\,\boldsymbol{d} - \boldsymbol{g}\,] = \boldsymbol{z} \le \boldsymbol{Z^+} \tag{30}$$

$$\boldsymbol{ZE^-} \le \boldsymbol{H_j}\,[\,\boldsymbol{d} - \boldsymbol{g}\,] = \boldsymbol{z} \le \boldsymbol{ZE^+} \qquad j=1,\ldots,LC \tag{31}$$

LC is the total number of emergencies that are considered. In order to ensure that performance standards are achieved, the security-constrained economic dispatch should be used for both the national and regional economic dispatches.

7. TRANSMISSION LOSSES CALCULATION

In all cases transmission losses shall be calculated according the mathematical expressions stated in this chapter.

For each transmission line that belongs to the TNM the transmission losses shall be estimated according the following expression:

$$PL_l \cong \sum_{q=1}^{QQ} \left[\frac{r_l * (q - 0.5) * zq * z_l}{V^2 * \cos^2 \varphi} \right] \tag{32}$$

Subject to:

$$z_l = \sum_{q=1}^{QQ} z_{l\,q} \tag{33}$$

$$z_{xy\,q} \le zq \tag{34}$$

Where:

PL_l = Transmission losses, expressed in MW, in line 'l', l = 1,….,L

r_l = Resistance of line 'l', l = 1,….,L

V = Voltage at which the TNM is operated. For losses calculation purposes it is assumed that V is the same at all nodes of the TNM.

cos φ = Power factor through each line that belongs to the TNM. For losses calculation purposes it is assumed that 'cos φ' is the same in all lines of TNM.

QQ = number of 'q' intervals in which the total load flow z_l is divided for linear approximation of losses.

$z_{l\,q}$ = length of 'q' interval, expressed in MW

zq = maximum length for each one of all 'q' intervals, expressed in MW

Finally, the total transmission losses 'Losses' for a Dispatch Interval on the whole TNM are as follows:

$$\text{Losses} = \sum_{l=1}^{L} PL_l \tag{35}$$