CHALMERS

# Grid Codes Comparison

Master thesis by

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We want to thank all our relatives and friends for their support, because with out it we could not have achieved this goal in our professional career and also to all our professors from whom we learned a lot, and to our supervisor for his patience and guidance for this project.

Studying at Chalmers was one of the best things that could have happened to us, the experience of meeting people and making friends from all over the world was amazing, thank you all.

## Sammanfattning

Efter avregleringen uppstod behovet att skapa nya organisationer, vars uppgifter är utveckling, implementering och uppdatering av olika tekniska specifikationer för att koordinera elmarknaden. De här organisationerna är ansvariga för reglering av de nationella elnäten, men det finns även liknande organisationer i Europa, vars uppgifter består i att koordinera transmissionen mellan olika systemoperatörer.

Nätanslutningsvillkor är de tekniska specifikationer som huvudsakligen bestäms av systemoperatörerna (eng Transmission System Operators TSO). De här specifikationerna följer inte en bestämd mall, utan varje land har sina egna villkor beroende på olika nationella krav.

Målet med den här uppsatsen är att undersöka de olika nätanslutningsvillkoren som finns i de utvalda länderna (USA, Sverige, Danmark, Tyskland, Nya Zeeland, Sydafrika och Indien) och att även undersöka de regionala skillnader som finns i vissa av länderna.

Slutligen presenteras även ett förslag till det optimala nätanslutningsvillkoret, vilket innehåller de viktigaste parametrarna.

# Preface

This thesis is written to provide information related to technical specifications between the process of generation and the transmission of the electricity, this requirements are generally called grid codes or interconnection guidelines.

The principal interest of this work is to compare and evaluate the different grid codes emitted by some countries.

# Abstract

After the deregularization a need emerged to create organizations in charge of the development, implementation and update of different technical specifications to coordinate the electrical market. This type of organizations are responsible fro regulating on a national level, nevertheless different organizations exist in Europe, whose main function consists on the transmission coordination for different system operators.

The grid codes are the technical specifications emitted principally by the Transmission System Operators (TSO). These sets of regulations do not follow a specific format since every country elaborates its own grid codes according to their requirements.

The aim of this thesis consists on investigating the different grid codes emitted by each of the selected countries (United Status of America, Sweden, Denmark, Germany, New Zealand, South Africa and India) and in the same way, the regional organizations to which they belong are also compared.

Finally an optimal grid code is presented, which contains the principal requirements that a grid code must contain.

## Terminology

***Buchholz protection***. - Which is meant to detect faults in the transformer by sensing oil movements or the presence of gas, subsequent to an internal disruptive discharge.

***Criteria (n-1)***. - Is a way of expressing a level of system security entailing that a power system is assumed to be intact with the exception of the loss of one individual principal component (production unit, line, transformer, bus bar, consumption etc.). Correspondingly, (n-2) entails two individual principal components being lost.

***Dead band***. - Is set intentionally on a machine controller. A distinction must be drawn here between the undesired neutral zone which is a function of inadequacies in the design of the controller, and the dead band, which is selected intentionally.

***Earth fault factor***. - At a selected location of a three phase system (generally the point of installation of equipment) and for a given system configuration, the ratio of the highest root mean square phase to earth power frequency voltage on a sound phase during a fault to earth (affecting one or more phases at any point) to the root mean square phase to earth power frequency voltage which would be obtained at the selected location without the fault.

***Farm controller***. - Regulating function and interface for a wind farm which enables the wind farm to be regulate locally and remotely.

***Flicker***. - Voltage fluctuations that may be noticeable as visual lightning variations and can damage or disrupt the operation of electronic equipment.

***Grid owner***. - The body that owns and operates any part of the gird.

***House load operation***. - Is the operation of a unit with its own auxiliary machinery as its only load when the unit is disconnected from the external power grid.

***Isolation***. - Means an electrical disconnection of part of a system of plant and/or apparatus from the remainder of the system, including from low voltage in feeds, either by an isolating device in the isolating position.

***Power system stabilizer (PSS)***. - Is a supplementary controller, which is often applied as part of the excitation control system. Grid codes and regulatory agencies are increasingly specifying PSS controls for new generation and retrofit on existing units.

***Steady state (power oscillations)***. - If the electric power system or a synchronous machine previously in the steady state reverts to this state again following a sufficiently “minor” fault; it has steady-state stability. If no control equipment is involved in this process, the characteristic is described as natural steady-state stability, otherwise as artificial steady-state stability. The instabilities may be a single swing or oscillatory.

***Stop wind velocity***. - The maximum wind speed at shaft height at which a wind turbine is constructed to produce energy IEC 60050-415

***Synchronous interconnection***. - means that individual systems are connected and being run together, at the same frequency, assist each other if a disturbance occurs in a system. Vice-versa this also means that major disturbances might propagate throughout this whole interconnected system and endanger its stability.

***Transient stability***. - Should an electric power system which has suffered a ”major” failure progress through decaying transient phenomena to its original steady state, it demonstrates transient stability with regard to the nature, location and duration of this fault. The steady state following a fault may be identical to that prior to the fault, or may differ from it. The nonlinear formulae for synchronous machines must be used for analysis of the transient stability.

***Wind farm****.* - Is a collection of several wind turbines with equipment (for instance internal network for connection to the connection point).

# Nomenclature

| ITEM | DEFINITION |
|---|---|
| BGM | Balancing Group Manager (in Germany) |
| BS | British Standards Institution |
| BWR | Boiling Water Reactor |
| CEA | Central Electricity Authority |
| CCGT | Combined Cycle Gas Turbine |
| CENELEC | European Committee for Electrotechnical Standardization |
| Connectee | Describes those who operate a connection of the high and extra high voltage networks in Germany. |
| CTU | Central Transmission Utility (in India) |
| DLC | Dead Line Charging |
| DVG | Deutsche Verbundgesellschaft |
| ENE | E.ON Netz GmbH is the transmission system operator for the high voltage networks in Germany. |
| Euronorm | European Norms |
| IDMT | Inverse Definite Minimum Time |
| IEC | International Electrotechnical Commission |
| IPS | Interconnection of the Power System (in South Africa) |
| ISGS | Inter State Generating Station (in India) |
| ISTS | Inter State Transmission System (in India) |
| LDC | Load Dispatch Centre (in India) |
| MCR | Maximum Continuous Rating is the hourly evaporation that can be maintained for 24 hours |
| NER | National Electricity Regulator (in South Africa) |
| NGC | National Grid Company (in UK) |
| NTC | National Transmission Company (in South Africa) |
| PWR | Pressurised Water Reactor |
| REA | Renewable Energies Act |
| REB | Regional Electricity Board (in India) |
| RLDC | Regional Load Dispatch Centre (in India) |
| SEB | State Electricity Board (in India) |
| SLDC | State Load Dispatch Centre (in India) |
| STU | State Transmission Utility (in India) |
| TNSP | Transmission Network System Providers (in South Africa) |
| VET | Vattenfall Europe Transmission |

## Index

# I. Introduction and grid code requirements

## I.1 Background

Before the privatization and liberalization of the electricity market; generation, transmission and distribution of electricity, could be managed by the same company.

After the deregulation process there are different companies in the electricity market. As a consequence, utilities around the world have prepared grid code documents which specify plant performance to meet the technical specifications and operational characteristics. The grid code documents will vary depending on the local regulatory, legal and technical environment.

## I.2 Introduction

Grid codes or interconnection guidelines started to appear on a widespread basis about 10 years ago in many countries around the world. There are certain common specifications that appear in a large amount of codes/guidelines, many of them are of no particular consequence; however several of them are of great significance to plant capital cost, efficiency and operating/maintenance requirements.

Many transmission grid codes now include a clause that requires each generation license to provide simulation models of proposed power plants as a part of the connection condition compliance. However each grid authority sets its own standards as regards to the model complexity and validation requirements.

Awareness began to grow in the electric power industry of the need for improved models and understanding of wind generation technology and plant operation. Over the past five years, this awareness has blossomed into the recognition that the generator interconnection process and requirements, as developed for conventional generating plants, may not be entirely adequate for wind power generation.

It is important to note that in addition to meeting the grid code requirements, all centrally dispatched generating plants are required to have the facility to set the levels of the generator output power and target frequency to the instructions issued by the grid operator and for the provision of ancillary services.

## I.3 Grid code definition

“To safeguard the electrical power system under liberalized electricity markets, grid codes were written in different countries specifying the technical and operational characteristics of plants owned by the different parties involved in the production, transport and consumption of electric power. This is necessary in order to ensure a certain level of quality of supply which must be delivered to the end users”[1].

“Grid code is a technical document containing the rules governing the operation, maintenance and development of the transmission system.”[2]

[1] Stephan, C. and Baba, Z, “Specifying a turbogenerator’s electrical parameters guided by standards and grid codes” *IEEE Electric Machines and Drives Conference* 2001

[2] Grid code, ESB National Grid

### I.4 Grid code requirements

The grid code is intended to establish the reciprocal obligations of all participants who are part of the transmission system operator. The grid code shall ensure the following:

1) Planning code that provides for the supply of information for planning and development studies.

2) The connection conditions which specifies a minimum of technical, design and operational plant criteria, regarding:

   Quality of supply
   - Voltage variation
   - Frequency variation
   - Harmonic distortion
   - Unbalance

   Protection specification
   - Main
   - Back-up
   - Breaker failure
   - Bus bar
   - Loss of excitation
   - Pole slips

   Generating plant specification
   - Power factor
   - Short circuit ratio
   - Output and operation at off nominal frequency
   - Active and reactive output with voltage variation
   - Speed control
   - Voltage control
   - Automatic voltage regulation (AVR)
   - Frequency issues

   Metering and monitoring requirements

   Wind power
   - Voltage and power factor
   - Frequency
   - Active and reactive power
   - Quality
   - Isolation
   - Control Points
   - Signals and communications

3) Operating code contains details for high level operational procedures for example demand control, operational planning and data provision.

### I.5 Project definition

There are many rules and polices in every grid code dealing with generation, transmission, distribution, protection, buying and selling policies, ancillary services, etc. For this analysis, the main concern is the connection requirements for the generation of electricity to the transmission grid. A selection was made from one or more countries from each continent, the countries selected are United States, New Zealand, India, South Africa, United Kingdom, Germany, Denmark and Sweden.

The next table shows a summary about the different transmission system operators, by continent, region and the responsible department by each country.

| Continent | Country | Transmission System Operator (TSO) | | |
|---|---|---|---|---|
| | | *Continent* | *Region* | *Responsible department* |
| Europe | Germany | ETSO[1] | UCTE[2] | Verband der Netzbetreiber- VDN- e.V. beim VDEW |
| | United Kingdom | ETSO | UCTE/UKTSOA[3] | BETTA (British Electricity Trading and Transmission Arrangements) |
| | Denmark | ETSO | UCTE/NORDEL | Elkraft |
| | Sweden | ETSO | UCTE/NORDEL | Svenska Kraftnät |
| Africa | South Africa | | | NER(National Electricity Regulator) |
| America | USA | | | NERC (North America Electric Reliability Council) |
| Oceania | New Zealand | | | Transpower |
| Asia | India | | | ISTS (Inter State Transmission System) |

Table 1.1 Responsible of the transmission system operators (by country).

[1]ETSO (European Transmission System Operator)
[2]UCTE(Union for the Co-ordination of Transmission Electricity)
[3]UKTSOA (United Kingdom Transmission System Operator Association)

## II. Transmission system operators organizations

Transmission System Operators (TSOs) are responsible for the bulk transmission of electric power on the main high voltage electric networks. TSOs provide grid access to the electricity market players (i.e. generating companies, traders, suppliers, distributors and directly connected customers) according to non-discriminatory and transparent rules. In order to ensure the security of supply, they also guarantee the safe operation and maintenance of the system. In many countries, TSOs are in charge of the development of the grid infrastructure too.

In Europe, we can find different organizations responsible for the regulation of the electricity market. In the next part of this chapter we present a brief explanation about the different transmission system operators by region and by country.

**ETSO** (European Transmission System Operator) is the organization in charge "of the development, harmonization and establishment rules in order to enhance network operation and maintain transmission system security, facilitate the internal European market for electricity; These objectives will be achieved with the technical expertise support from the Regional TSOs Associations: **NORDEL**, **UCTE**, UKTSOA and ATSOI."[3](See figure 2.1)

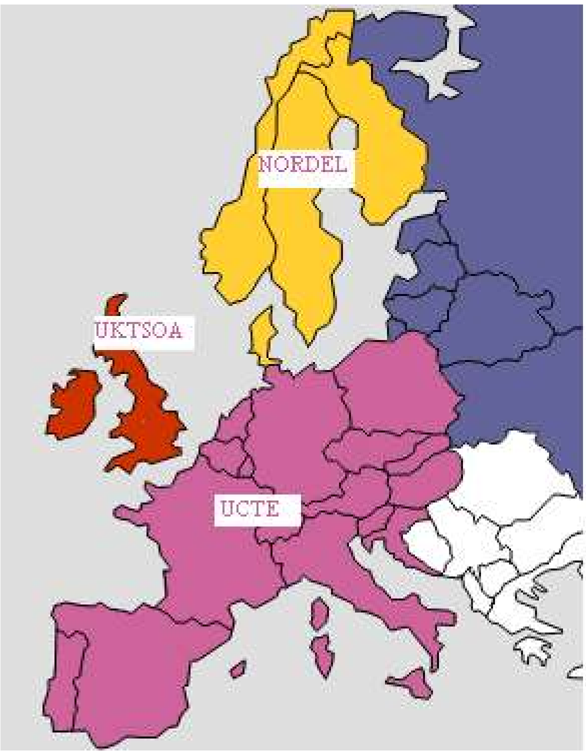



Figure 2.1 ETSO zone.

The "Union for the Co-ordination of Transmission of Electricity" (**UCTE**) is the association of transmission system operators in continental Europe, providing a reliable market base by efficient and secure electric "power highways".

The **UCTE** "coordinates the operation and development of the electricity transmission grid from Portugal to Poland and from the Netherlands to Romania and Greece. **UCTE**, the association of transmission system operators in continental Europe in 23

[3] http://www.etso-net.org

countries, provides a reliable market platform to all participants of the Internal Electricity Market (IEM) and beyond."[4]

"**Nordel** is a body for co-operation between the TSOs in the Nordic countries (Denmark, Finland, Iceland, Norway and Sweden), whose primary objective is to create the conditions for, and to develop further, an efficient and harmonized Nordic electricity market. It also serves as a forum for contact and co-operation between the TSOs and representatives of the market players in the Nordic countries. In order to create the right conditions for the development of an efficient electricity market, it is important for the TSOs to be able to consult with the market players. Likewise, it is important for the market players to be given the opportunity to make useful contributions and proposals to the TSOs. A market forum has been set up within the new Nordel organization in order to pursue this dialogue."[5]

## *II.1 Transmission system operators in specifications*

The **ETSO** does not have a grid code but all the regional transmission system operators should follow the standard specifications in order to enhance network operation and maintain transmission system security.

The regional TSOs have interconnection guidelines, for example **Nordel** grid code was developed for the transmission systems operators in Scandinavia and Finland. The code is a collection of rules concerning the interconnected Nordic grids.

Another case is the "**UCTE** Operation Handbook". This is an up to date collection of operation principles and rules for the transmission system operators in continental Europe. This operation handbook therefore serves as the reference ("legislation") for the grid operation by the TSOs and guarantees the UCTE's quality and reliability standards.

In the following section a comparison is made among the requirements for transmission capacity, frequency, voltage, emergency conditions, thermal and hydro power units and renewable energies for the transmission system operator's organizations in Europe.

### *II.1.1 Transmission capacity*

In the **Nordel** grid code, the transmission capacity is determined by 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 usually low, between 5 and 10 % and it is agreed between Nordel and the TSOs.

There are some requirements for interconnections between **Nordel** and other areas which are:

The control systems for new HVDC interconnections should be adapted so that the risk of multiple commutation failures in the event of a dimensioning fault is minimized.
Frequency controlled step or ramp variation of the power is permitted when the frequency is below 49.5 Hz.
The rules shall be used for the joint, synchronized Nordic transmission grid. This concerns principally the main grid, mainly 220 - 420 kV.

[4] http://www.ucte.org
[5] http://www.nordel.org

The maximum transmission capability through a constraint, or for single lines following a simple fault, can be set at a given percentage over the nominal limit in cases when the constraint/line can be relieved within 15 minutes.

The transmission capacity is determined on the basis that the grid must withstand the dimensioning fault *(n - 1).* The (n - 1) criterion also applies to the **UCTE** area.

ETSO does not have any specification about transmission capacity. All the countries that form part of ETSO have their own grid code.

### *II.1.2 Frequency*

The frequency is one of the most important parameters in all the networks, for that reason in Nordel and UCTE interconnection guidelines explain in detail the entire criterion related with the connections in the transmission network.

According to the different grid code, the permissible variation in the **Nordel** grid of the frequency during normal state is between 49.9 and 50.1 Hz. For the **UCTE** the nominal frequency in all the synchronous areas is 50 Hz  0.1Hz

The frequency response in the **Nordel** power system shall be a minimum of 6,000 MW/Hz for the synchronous system throughout the frequency range of 49.9 - 50.1 Hz. The requirement regarding the frequency response is distributed between the subsystems in accordance with last year's annual consumption. 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.

**Nordel** power system and **UCTE** grid are responsible for frequency control.

The primary control maintains the balance between generation and demand in the network using turbine speed governors. **UCTE** requirements for the primary frequency control are:

The nominal frequency value in the synchronous area is 50 Hz.
The primary control is activated if the frequency deviation exceeds ±20 mHz.
The quasi-steady state frequency deviation in the synchronous area must not exceed ±180 mHz.
The instantaneous frequency must not fall below 49.2 Hz.
Load shedding (automatic or manual, including the possibility to shed pumping units) starts from a system frequency of 49.0 Hz (or below).
The instantaneous frequency must not exceed 50.8 Hz.

The time for starting the action of primary control is a few seconds starting from the incident, the deployment time for 50 % or less of the total primary control reserve is at most 15 seconds and from 50 - 100 % the maximum deployment time rises linearly to 30 seconds.

Requirements for primary control:

The accuracy of local frequency measurements used in the primary controllers must be better than or equal to 10 mHz.
The insensitivity range of primary controllers should not exceed ±10 mHz.

The reference incident is the maximum instantaneous deviation between generation and demand in the synchronous area[6], (by the sudden loss of generation capacity, load shedding/loss of load or interruption of power exchanges) to be handled by primary control starting from undisturbed operation and depends on the size of the area or zone and on the size of the largest generation unit or generation capacity connected to a single bus bar located in that area[7]. See figure 2.2.

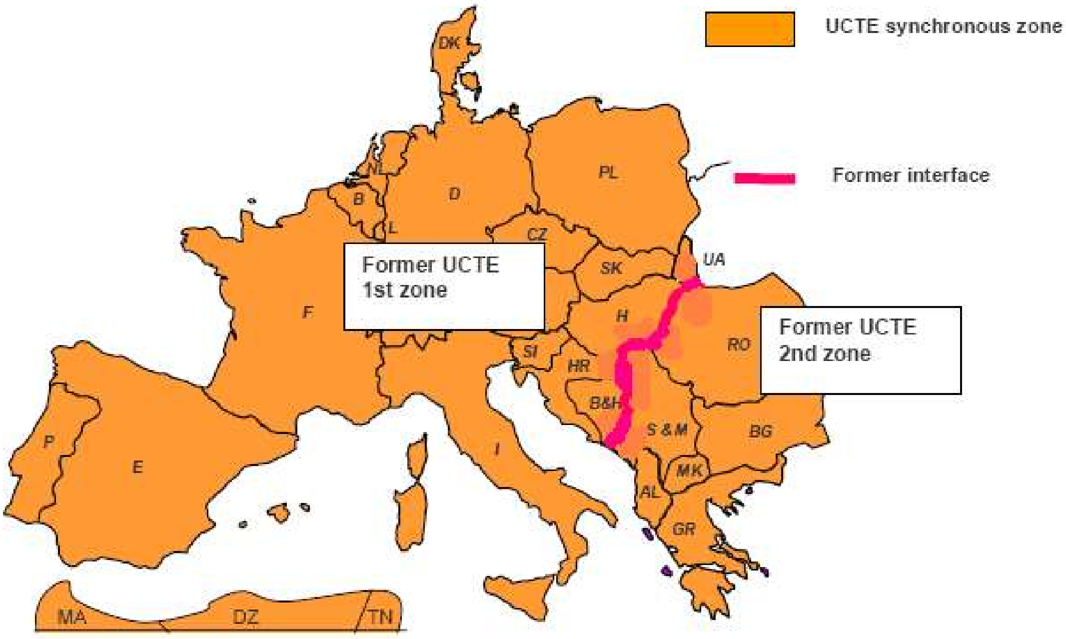



Figure 2.2 UCTE Synchronous zone[8]

For the first synchronous zone as in 2003 the maximum power deviation to be handled was 3000 MW, assuming realistic characteristics concerning system reliability and size of loads and generation units.

For the second synchronous zone as in 2003, the maximum power deviation to be handled was 540 MW.

For other synchronous areas (**UCTE** synchronous areas), that are not connected to the main synchronous zone, the size of the reference incident needs to be defined in each particular case with respect to the size of the area and the size of the largest generation units located in that area.

Generally within **UCTE**, it is applicable that the delivery of secondary reserves shall be commenced within 30 seconds after an imbalance has arisen between production and consumption and shall be fully regulated out after 15 minutes. There must be sufficient reserves to safeguard each area's own balance following a loss of production. Time deviation in **UCTE** should be an aim to keep the time deviation **Δ**T

[6] The definitions of synchronous zones (first and second zone as existing today as a result of the Balkan war) are temporal only due to the planned reconnection of the UCTE area. The reconnection was scheduled for 2005. The system load for the first SYNCHRONOUS AREA typically varies between 150 GW off-peak and 300 GW peak.
[7] The final values used in the definition of the reference incidents are determined by the UCTE SG "TSO-forum" and finally confirmed by the UCTE WG "Operations and Security" and the UCTE SC. The values given are under consideration.
[8] www.ucte.org

within the time range of ±30 seconds. The time deviation shall be corrected during quiet periods with high frequency response and with a moderate frequency deviation.

### *II.1.3 Voltage*

The lowest operating voltages in the **Nordel** pool at each voltage level are highly dependent on the local conditions and are reached during operational disturbances and are usually not lower than 90 % of the nominal voltage see table 2.1.

| Nominal voltage or rated voltage | Used for transmission in | Highest operating voltage | Withstand voltage for lightning surge | Withstand voltage for switching surge | 50 Hz, 1 min withstand voltage |
|---|---|---|---|---|---|
| 110 | Finland | 123 | 550 | - | 230 |
| 132 | Denmark, Norway | 145 | 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 | 1050 | - |

Table 2.1 Voltages and slow voltage variations above 110 kV.

Depending on local conditions in the countries that are part of **Nordel**, the voltage imbalance 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.

The voltage control in **UCTE** is thus primarily a regional problem, which may involve several TSOs in an interconnected system. The operating voltage reference values are: 380 kV or 400 kV and 220 kV or 225 kV. These nominal voltage values, 380 kV or 400 kV and 220 kV or 225 kV are slightly different depending on country equipment design; 750 kV is an accepted operating voltage reference level too. They do not introduce significant differences on the synchronously interconnected system operation.

### *II.1.4 Time*

Only UCTE has specifications for time. The main reason is the different time zones, the Scandinavian countries are in the same zone time.

The objective of time control in the **UCTE** organization is to monitor and limit discrepancies observed between synchronous time and Universal Time Coordinated (UTC) in the synchronous area (within each zone of synchronous operation of the **UCTE** separately). A tolerated range of discrepancy between synchronous time and UTC time is within a range of ±20 seconds.

### *II.1.5 Emergency conditions*

Emergency situations in the interconnected **UCTE** system occur as a result of abnormal operation caused by dropping of generating power, outages/overloading of transmission lines that could not be covered by the operational reserve of affected TSOs and cause imbalance of active power or voltage decline. According to the actual system frequency, the following operating conditions and emergency conditions are defined:

If the absolute deviation from the nominal system frequency of 50 Hz does not exceed 50 mHz, operation qualifies as undisturbed (normal operating condition).
If the absolute frequency deviation is greater than 50 mHz but less than 150 mHz, operating conditions are deemed to be impaired, but with no major risk, provided that control facilities (controllers and reserves) in the affected control areas/blocks are ready for direct deployment.
If the absolute frequency deviation is greater than 150 mHz, operating conditions are deemed to be severely impaired, because there are significant operational risks for the interconnected network.
If the frequency deviation reaches the critical value of 2.5 Hz (that means that the system frequency reaches 47.5 Hz, for over frequency the limit is 51.5 Hz), automatic disconnection of generators is triggered and the operation of the interconnected network is at its limit.

The units in the **Nordel** network 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. 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.

### *II.1.6 Thermal and hydro power units*

Production for thermal power and hydro power units in the **Nordel,** plants must be capable of automatically contributing to frequency regulation of the electric power system with a variation of 50 ± 0.1 Hz. All the generating units must have a unit controller and an adjustable frequency turbine regulator set point in the range from 49.9 - 50.1 Hz.

**Nordel** 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 seconds, in conjunction with network disturbances and at a generator busbar voltage of 70 % of the rated generator voltage.

For power response capability during power system disturbances in the **Nordel** grid, the demand from the power system is that the instantaneous power response shall be available within 30 seconds after a sudden frequency drop to 49.5 Hz. Half of that power response shall be available within 5 seconds after the frequency drop.

For power units in **Nordel** between 100 MW and 25 MW the regulations are the same as the specifications for thermal power units above 100 MW for:

Minimum output.
Starting time.
Operational modes and power step change limiter.
Load following and power response rate and range.
Instantaneous power response and power step change for fossil fuel.

In the **UCTE** operation handbook there are no specifications for the thermal and the hydro power units.

### *II.1.7 Renewable Energies*

Nowadays renewable energies are an important topic for all the transmission system operators, the main point of this topic refers to the connections into the transmission system network; the different organizations around Europe are studying all the technical requirements specially for wind power, below are the principal points for the grid connection for the **UCTE** and **ETSO** until this moment.

1) The **UCTE** technical requirements for grid connection.

The technical requirements for connection to the transmission network are defined at the delivery point and they are a set of values concerning frequency, voltage, short circuit power and stability. Renewable energies are mostly exempted from the requirement of island operating after disconnection.

In all operational conditions, wind farms shall be able to withstand certain fault sequences without being disconnected, for instance a three phase fault with a certain clearing time or a two phase fault with an unsuccessful reclosing after a certain time.

Mostly at the connection point the exchange of reactive power should be more or less zero (within a defined margin, depending on the actual output). In some countries, by agreement between wind power owner and the grid company, the compensation task can also be assigned to the grid owner. But the generators should be designed to be able to meet a certain range of reactive power exchange able for instance between a power factor of 0.9 leading and 0.9 lagging at full active power output.

Renewable energies have a production limitation and it must be possible to reduce the power output in any operating condition and from any operating point (for instance in the range of 20 - 100 % of the rated power) to a maximum power value (set point value) specified by the TSO.

The switching and control of reactive power is mostly limited to a certain percentage of the maximum connection capacity (for instance 2.5 -10 %).

In general the rapid voltage change because of switching should be limited to a maximum of 2 or 3 %.

2) The **ETSO** technical requirements for grid connection.

The grid operator is responsible for the secure and stable operation of the public grid. This responsibility cannot be shared with other parties. Therefore the grid company needs full control and property of the meshed grid. This includes the measurement equipment needed for billing.

The new renewable energies will very often need new infrastructure, especially the present and future capacity of wind farms, this will lead some countries to significant grid extension programs to secure stable network operation and transport the electricity from the wind farm sites to the load centers.

The integration of new renewable plants with several thousand of MW makes new connecting rules and proper incentives necessary to avoid negative effects on the existing electric system. These rules should basically be harmonized across Europe, because system stability (especially in the synchronous UCTE area of continental Europe) is not limited to single countries.

### *II.2 Transmission System Operator by country*

The countries chosen for this analysis have different organizations (TSOs) that are in charge of regulation, operation and maintenance of the electricity transmission system. In the next part of this report we show a brief explanation of these organizations.

#### *II.2.1* ***United States of America***

It is important to note that there is no "national power grid" in the **United States**. In fact, the continental United States is divided into three main power grids:

The eastern interconnected system or the eastern interconnect
The western interconnected system or the western interconnect
The Texas interconnected system, or the Texas interconnect

The regional reliability councils of the North American Energy Reliability Council (NERC) members are the ten regional reliability councils whose members come from all segments of the electric industry: investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; and end-use customers (see figure 2.6).

ECAR - East Central Area Reliability Coordination Agreement.
ERCOT - Electric Reliability Council of Texas.
FRCC - Florida Reliability Coordinating Council.
MAAC - Mid-Atlantic Area Council.
MAIN - Mid-America Interconnected Network.
MAPP - Mid-Continent Area Power Pool.
NPCC - Northeast Power Coordinating Council.
SERC - Southeastern Electric Reliability Council.
SPP - Southwest Power Pool.
WSCC - Western Systems Coordinating Council.

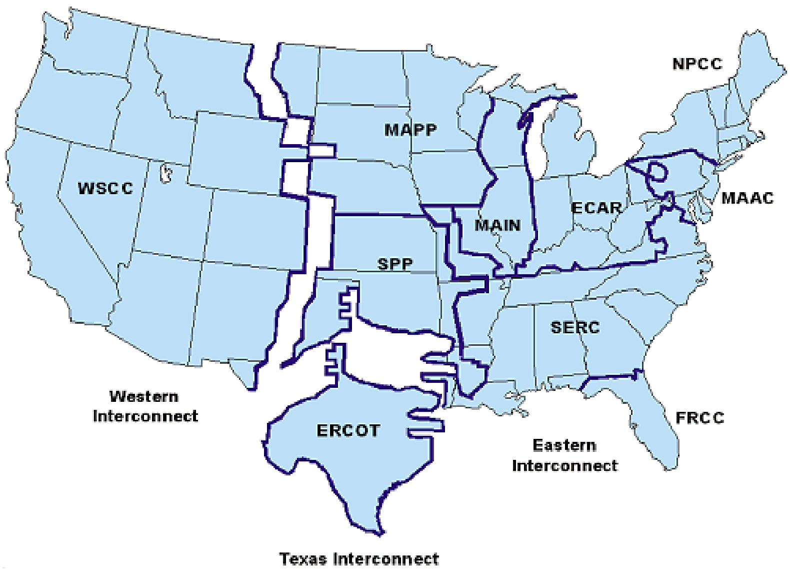



Figure 2.6 Distribution of the NERC's members in the USA.

Some states have passed the control of the grids to the Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs).

- California ISO.
- ERCOT (Texas).
- ISO New England.
- Midwest ISO.
- New York ISO.
- PJM Interconnection (Mid-Atlantic).
- Regional Transmission Organization for New England.

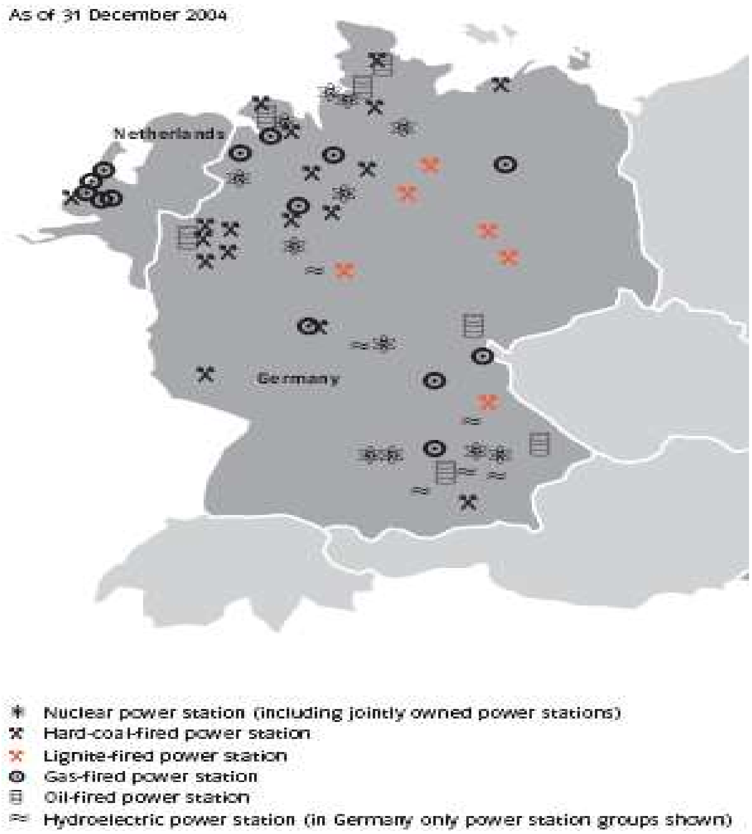
The Federal Energy Regulatory Commission (FERC) having authority over the entire interconnected electric grid, has established the NERC operating guidelines as the guiding standards and practices for all jurisdictional utilities

The interconnection guidelines that will be used are from Otter Tail power company, like many other companies, Otter Tail also adheres to the existing manuals , standards, and guidelines for the NERC, ISO's or any agency related to the operation and reliability of the North American electric interconnected transmission grid.

### *II.2.2 Germany*

Verband der Netzbetreiber (VDN) is responsible to regulate the essential requirements for interconnections with the national grid, see figure 2.7. The German grid code consists of three parts:

- Grid code high and extra high voltage: E.ON Netz GmbH, Bayreuth, Germany August 2003.
- Transmission code 2003, which are the network and system rules of the German transmission system operators.
- Grid code, which contain the rules of cooperation for the German transmission system operators.



[9]

Figure 2.7 Distribution of the different powers plants in **Germany**.

### *II.2.3 South Africa*

The Grid Code and the Market Code are the two main documents in terms of which the electricity market will be governed. The areas covered in each code are illustrated in figure 2.8 These codes have been developed by an Electricity Supply Industry (ESI) and the National Electricity Regulator (NER), particularly those published by “The National Grid Company” (UK) and the “National Electricity Code Administrator” (Australia), have been accessed in order to assist with the drafting. The NER´s responsibility is to regulate the future market participants in the electricity market.

[9] www.eon.com


Figure 2.8 Content of codes

### *II.2.4 United Kingdom*

The transmission system in **United Kingdom** is organized by:

National Grid Company (NGC), who is responsible for maintaining a grid code for English and Scottish systems, the grid code emitted by NGC was introduced in March 1990 and this first issue was revised 31 times. In March 2001 the actual Grid Code was introduced.
Scottish Power and Scottish and Southern Energy in Scotland, two vertical integrated companies.
Northern Ireland Electricity in Northern Ireland.

In this paper we consider the NGC grid code and the Scottish grid code because they are the most representative codes in the UK.

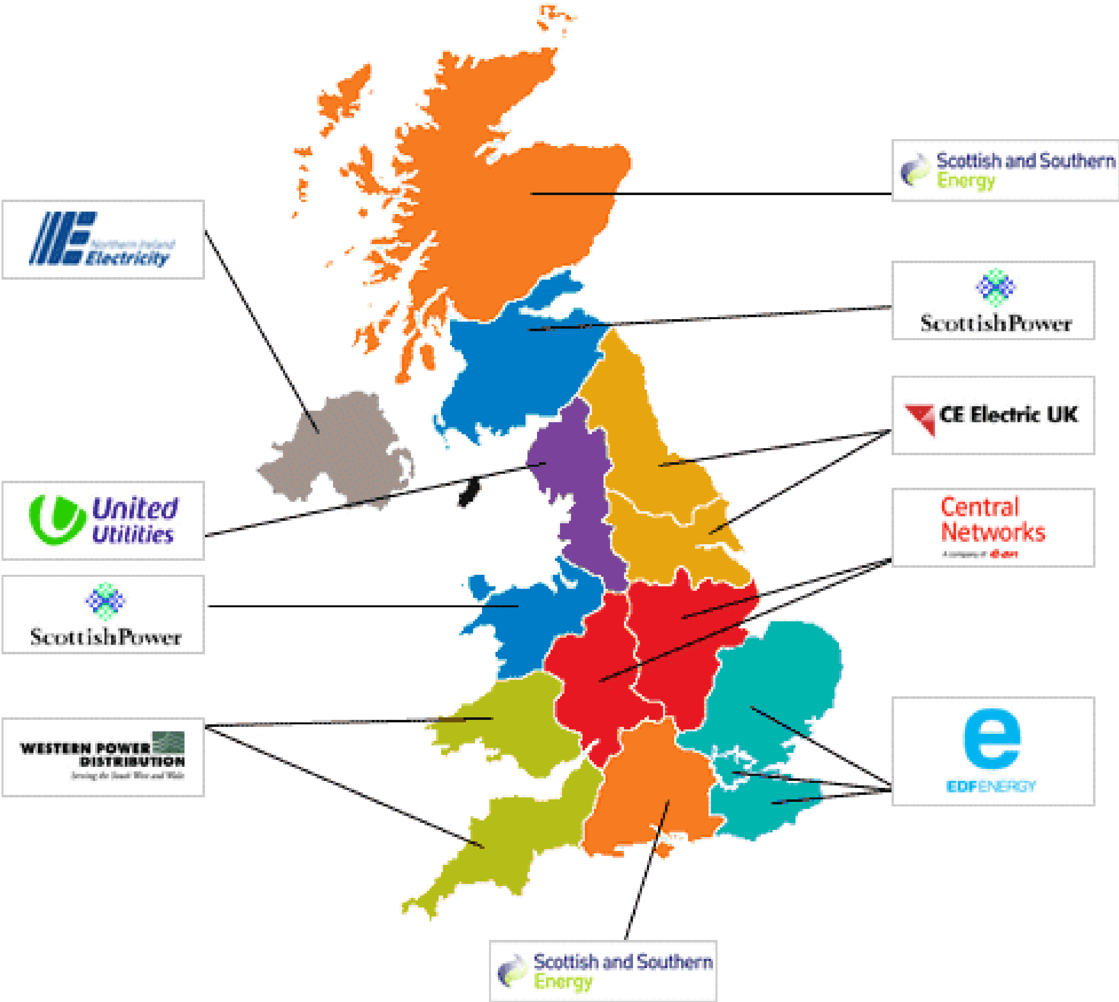



Figure 2.9 Distribution network operator companies in United Kingdom[10].

### *II.2.5 Denmark and Sweden*

**Demark and Sweden**, are governed by, as shown in the figure 2.10. For that reason their technical and operational characteristics are based on the Nordel grid code.

Nowadays renewable energy is one of the key issues in European energy policy. For that reason, after 1 July 2004, Denmark has special technical requirements for wind power plants.

[10]http://www.nationalgrid.com/

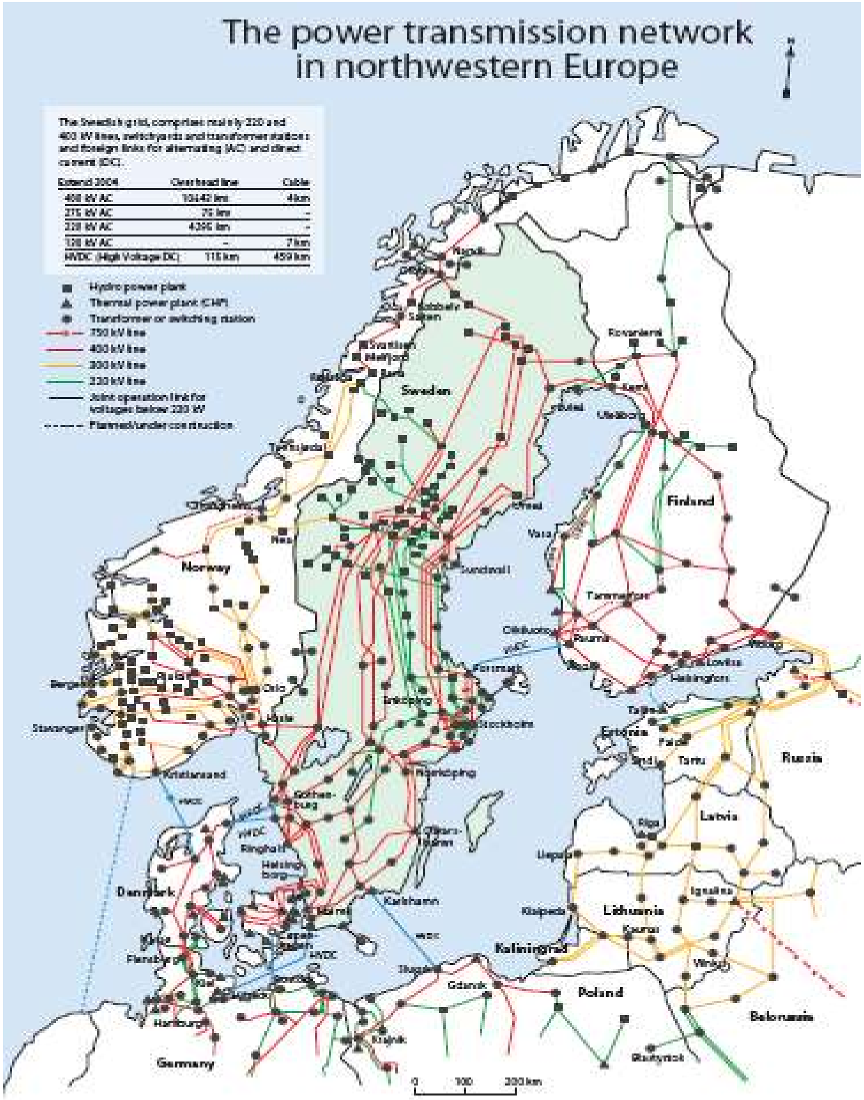



Figure 2.10 Nordel interconnections.

### *II.2.6 India*

Powergrid India was integrated in October, 1989 for establishment and operation of regional and national electrical power grids (figure 2.11)

The transmission of energy within the territory of a state on a system built, owned, operated, maintained or controlled is done by the Central Transmission Utility (CTU) or by any person/agency under the supervision and control of a central transmission utility.

In India, the central transmission utility, shall exercise supervision and control over the Inter State Transmission System (ISTS).

The Inter state transmission system, is the system for the conveyance of energy by means of a main transmission line from the territory of one state to another state and includes; the conveyance of energy across the territory of an intervening state as well as conveyance within the state which is incidental to such inter state transmission of energy.


Figure 2.11 Principal cities in India.

### *II.2.7 New Zealand*

In New Zealand Transpower is the asset owner and system operator of New Zealand's high voltage electricity transmission grid.

Transpower is the owner of the high voltage transmission grid (the national grid) which transmits electricity throughout the country (see figure 2.12). The grid comprises approximately 12,000 km of transmission lines and 170 substations and switchyards.

As a system operator Transpower is responsible for the real time co-ordination of electricity transmission throughout New Zealand and provides scheduling and dispatch services. Generating companies offer electricity at a price of their choice and retailers make bids to buy certain quantities at different prices. Transpower works out the amount of electricity that needs to be generated for a particular half hour period so demand will equal supply and also maintains the common elements of quality of supply for the electricity industry.


Figure 2.12 North and South Islands in New Zealand.

## III. Generating units

Rotating turbines attached to electrical generators produce most commercially available electricity. Turbines may be driven by using steam, water, wind or other fluids as an intermediate energy carrier. The most common usage is by steam in fossil fuel power plants or nuclear power plants, and by water in hydroelectric dams. Alternately, turbines can be driven directly by the combustion of natural gas. Co-generation gas turbines offer efficiencies of up to 60%, as they generate power both directly by combustion of natural gas and also use residual heat to generate electricity from steam.

## *III.1 Generator*

The generating unit is one of the most important equipments for the generation of electricity, there are many types of generating units, and since they are connected to the grid special consideration must be taken into account for their protection.

For the requirements relating to generator/NGC connection points in the **UK,** each connection between a generating unit or a CCGT module and the NGC transmission system must be controlled by a circuit breaker capable of interrupting the maximum short circuit current at the point of connection.

### *III.1.1 Non hydro and hydro units.*

In **South Africa**, tables 1 and 2 of Appendix A show the minimum requirements for units of the participants that are connected to the transmission system.

### *III.1.2 Thermal units*

The starting time for all types of thermal power units in **Sweden and Denmark** shall be defined according to planned utilization, these guideline shall apply to gas turbines for emergency and peak load generation, from rolling up to full output power:

Gas turbines of jet engine type, from 3 to 3.5 minutes.
Industrial gas turbines, from 10 to 15 minutes.

The operating time for thermal power units shall be designed so that they can operate for house load operation for at least 1 hour. Nuclear power units shall be capable of operating in house load operation for a duration determined by the nuclear safety conditions.

## *III.2 Power stations*

Requirements for power stations less than 1000 MW in **South Africa:**

If the local area depends on the power station for voltage support, the connection shall be made with a minimum of two lines.
Transient stability shall be maintained following a successfully cleared single phase fault.
If only a single line is used, it shall have the capability of being switched to alternative busbars and be able to go onto bypass at each end of the line.

Requirements for power stations of more than 1000 MW in **South Africa:**

With one connecting line out of service (n - 1), it shall be possible to transmit the total output of the power station to the system for any system load condition.
With the two most onerous line outages (n - 2), it shall be possible to transmit 83 % of the total output of the power station to the system.

### *III.3 Nuclear power stations*

The system operator shall provide secure off-site supplies, for the NTC obligations towards nuclear power stations in **South Africa,** as requested and specified by the relevant nuclear generators and facilities in accordance with the National Nuclear Regulatory Act (ACT 47 of 1999).

### *III.4 Requirements governing the connection of generating units*

In order to avoid system collapse due to a "bad connection" of the generating units to the grid, each country has different requirements and they will follow different standards. Stability in the transmission system must be kept at all times and for the start up of the generating unit synchronization plays an important role.

In the **USA,** the generating unit must meet all applicable American National Standards Institute (ANSI) and the Institute of Electrical and Electronic Engineers (IEEE) standards. The prime mover and the generator should be able to operate within the full range of voltage and frequency excursions that may exist on the electric company's system without damaging the unit.

The following conditions shall apply to such generating units in **Germany**:

The primary control band must be at least $\underline{+}2$ % of the nominal capacity.
The power-frequency characteristic shall be adjustable.
The generating unit shall be capable of activating, within 30 seconds, the total primary control power contractually agreed at an almost steady frequency deviation of ± 200 mHz, and of maintaining supply for at least 15 minutes.
In the case of more minor frequency deviations, the same rate of power change shall apply until the required power is reached.

#### *III.4.1 Stability of transmission systems*

Stable synchronous operation of the generating units in **Germany** is a prerequisite for secure and reliable interconnected operation and for customer supply.

For transient stability, with fault clearing times of up to 150 ms, three phase short circuits close to the power station must not lead to instability throughout the operating range of the generator when the system short circuit power on the network side of the "network/generating unit" interface following clearance of the fault exceeds six times the nominal active power of the generating unit.

The following minimum requirements in **Germany** shall be met as criteria placed upon the network for transient stability.

Where a number of generating units are operated through the same interface (busbar) on the network, the minimum system short circuit power shall be calculated from the sum of the nominal active generator powers.
Where a generating unit cannot be prevented from pole slipping following system short circuits, the generating unit must be disconnected from the network by the generator protection (e.g. pole slip protection, power station decoupling relay) in order to prevent consequences which place the general network and power station operation at risk.

Regarding steady state stability (*power oscillation*), experience has shown that phase swinging and power oscillations currently occur in the UCTE synchronous area at frequencies of 0.2 - 1.5 Hz. Phase swinging and power oscillations shall lead neither to tripping by the protective equipment of the generating unit, nor to a power reduction. The limit of steady state stability can already be reached as a function of the transmission distance, though current carrying capacities occur in the (n - 1) case which is clearly below the relevant maximum thermal current carrying capacities.

Should facilities for HVDC transmission in the **German** grid be employed for power exchange between TSOs, it shall be ensured that stability problems are not transmitted between the networks of the TSOs in question.

Transient stability shall be retained for the following conditions in **South Africa**:

A three phase line or busbar fault, cleared in normal protection times, with the system healthy and the most onerous power station loading condition.
A single phase fault cleared in "bus trip" times, with the system healthy and the most onerous power station loading condition.
A single phase fault, cleared in normal protection times, with any one line out of service and the power station loaded to average availability.

### *III.4.2 Synchronization*

The connection of the generators in **Germany** needs to be provided for:

Normal operation (start up of the generating unit);
Synchronization following tripping.

Synchronous generators and other generators with stand alone capability in the **USA** must use one of the following methods to synchronize without damage to the unit.

1) Automatic synchronization with automatic synchronizing relay to synchronize with the electric company's system. The automatic synchronizing relay must have all of the following characteristics:

    Slip frequency matching window of 0.1 Hz or less.
    Voltage matching window of $\pm$10 % or less.
    Phase angle acceptance window of $\pm$10 degrees or less.
    Breaker closure time compensation.

    Note: The automatic synchronizing relay sends a trip signal to the breaker after the above conditions are met.

2) Automatic synchronization with automatic synchronizer to synchronize with the electric company's system. The automatic synchronizer must have all of the following characteristics:

    Slip frequency matching window of 0.1 Hz or less.
    Voltage matching window of $\pm$10 % or less.
    Phase angle acceptance window of $\pm$10 degrees or less.
    Breaker closure time compensation. For an automatic synchronizer that does not have this feature, a tighter frequency window ($\pm$5 degrees) with a one second time acceptance window shall be used to achieve synchronization within $\pm$10 degrees phase angle.

    Note: The automatic synchronizer has the ability to adjust generator voltage and frequency automatically to match system voltage and frequency, in addition to having the above characteristics.

3) Manual synchronization with synchroscope and synch-check relay supervision. The synch-check relay must have the following characteristics:

Voltage matching window of ±10 % or less.
Phase angle acceptance window of ±10 degrees or less.

Generators with greater than 1,000 kW aggregate nameplate rating must have automatic synchronizing relay or automatic synchronizer.

All regional constituents in **India** shall endeavor to operate their respective power systems and power stations in synchronism with each other at all times.

### *III.4.3 Excitation system requirements*

An excitation system is required to regulate generator output voltage, in **USA:**

1) Static systems shall have a minimum ceiling voltage of 150 % of rated full load field voltage and a maximum response time of two cycles (0.033 seconds).
2) Rotating system shall have an ANSI voltage response ratio of 2.0 or faster.
3) Excitation systems shall respond to system disturbances equally in both the buck and boost directions.

### *III.4.4 Power system stabilizers (PSS)*

Power generation in the **USA** with properly tuned and calibrated PSSs, provide damping to electric power oscillations. Such damping improves stability in the electrical system and may prevent an individual generator from unnecessary tripping. To comply with the applicable reliability council requirements, generators of 75 MW or larger must be equipped with power system stabilizers to dampen power oscillations. The power system stabilizer is to be tuned to the electric company's system mode oscillation. **USA** has a more detailed synchronization of their generating units than other countries, and regarding PSS, they also play a very important role by damping electric power oscillations to improve stability.

Regarding the behavior during network disturbances PSS may be necessary for all generators in **Germany.**

In **Sweden and Denmark** PSS shall be included for each generator. The PSS shall be tuned to improve the damping of the oscillations of generator and power systems, especially the damping of low frequency (0.2 - 1.0 Hz) inter area oscillations.

# IV. Renewable energies

One of the hottest topics for renewable energy is the generation of electricity by means of wind, but since we cannot control wind, many precautions have to be taken into account when having wind generators connected to the grid in order to maintain stability and avoid system collapse.

## *IV.1 Requirements on renewable energies*

The principal aim of this project is to realize a comparison among the grid codes created by different transmission system operators. The majority of the countries analyzed in this document have wind power generation.

The technical specifications for the connection for this type of renewable energy into the transmission system do not form part of a specific grid code, with the exception of Germany, the rest of the countries count with connection guidelines, see table 4.1 where the official documents for the technical specifications regarding wind generation connection can be found.

| Country | Document | Responsible organization |
|---|---|---|
| Denmark | Wind turbines connected to grids with voltages above 100 kV and below 100 kV. | Eltra and Elkraft 2005 |
| Germany | Netz - und Systemregeln der deutschen Obertragungsnetzbetrelber/EEG Erzeugungsanlagen am Hoch - und Höchstspannungsnetz | VDN 2003 and 2004 |
| India | No specific document available | - |
| New Zealand | Wind energy integration in New Zealand | Energy Link and MWH NZ 2005 |
| South Africa | No specific document available | - |
| Sweden | Affärsverket Svenska Kraftnäts föreskrifter om driftsäkkerhetsteknisk utformning av produktionsanläggningar | Svenska Kraftnät 2002 |
| United Kingdom | Recommendations for the connection of embedded generating plant to public distribution systems above 20 kV on with outputs over 5 MW | Electricity Networks Association 2002 |
| USA | Standardizing generator interconnection agreements and procedures | The American Wind Energy Association |

Table 4.1 Documents concerning the technical requirements for wind generation.

In this paper we will not go into detail regarding wind generation, we will just mention some of their requirements.

### IV.1.1Voltage and power factor

See table 4.2 for the voltage limits for the **New Zealand** operating grid.

| Nominal voltage grid | Minimum voltage | Maximum voltage |
|---|---|---|
| 220 kV | 198 kV | 242 kV |
| 110 kV | 99 kV | 121 kV |
| 66 kV | 62.7 kV | 69.3 kV |
| 50 kV | 47.5 kV | 52.5 kV |

Table 4.2 Voltage limits for the New Zealand grid

The individual Wind Turbine Generators (WTG's) in the **USA** typically generate voltages ranging from just under 600 V. Each turbine will normally be equipped with a generation voltage to medium voltage (typically 12.47 - 34.5 kV) step up transformer that is either an integral part of the WTG assembly or installed adjacent to the wind turbine generators.

The proposed voltage requirements in **USA** are described in figure 4.1. The requirements apply to voltage measured at the point of interconnection. The point of interconnection is understood to be at the transmission voltage (i.e. on the high voltage side of the wind plant substation transformer).

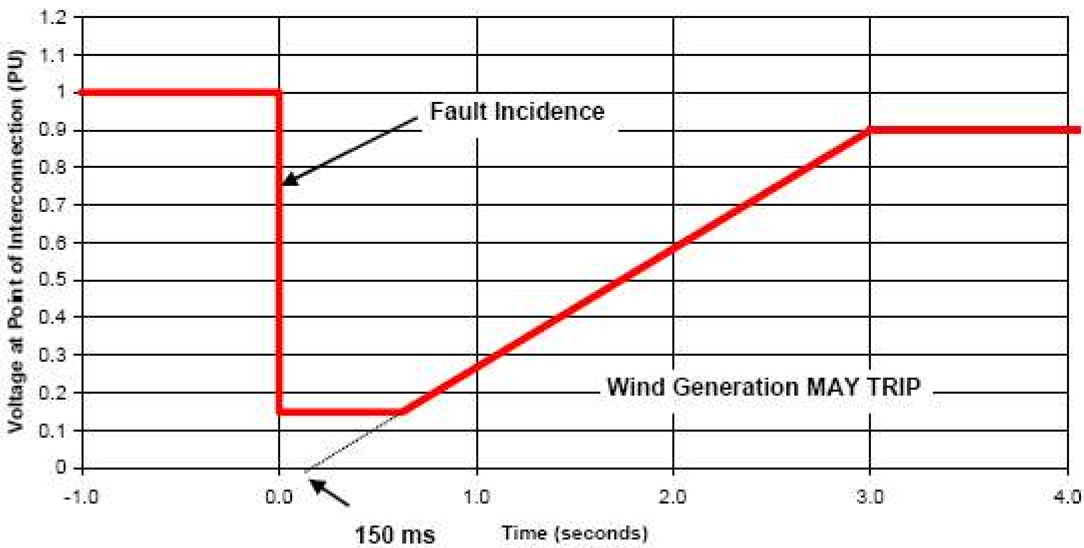



Figure 4.1 Response of WTGs to emergency low voltage

Wind turbines in **Germany** should be able to operate with different power factors in over excited as well under excited mode. Figure 4.2 shows the required power factor range of VE-T depending on the voltage on the network side. Because of the differences in topology and loadings of the particular networks German transmission grid operators may define the voltage level.

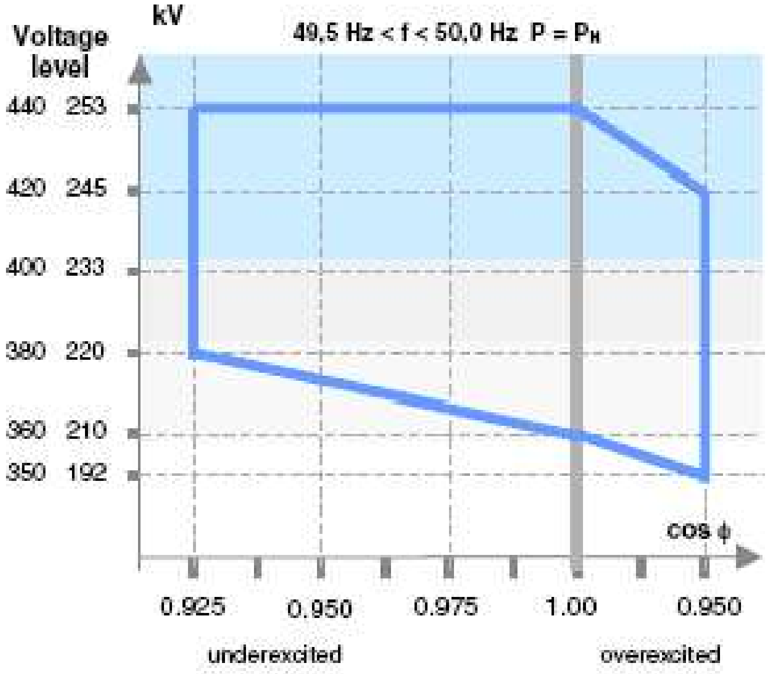



Figure 4.2 Operating range within the coordinates of voltage and power factor in Germany.

Wind turbines should remain connected to the grid during network faults. This requirement became essential due to the fact that thousands of MW wind power was at risk of being lost. Figure 4.3 shows new requirements where the lowest voltage that wind farms have to withstand is set at 15 %.

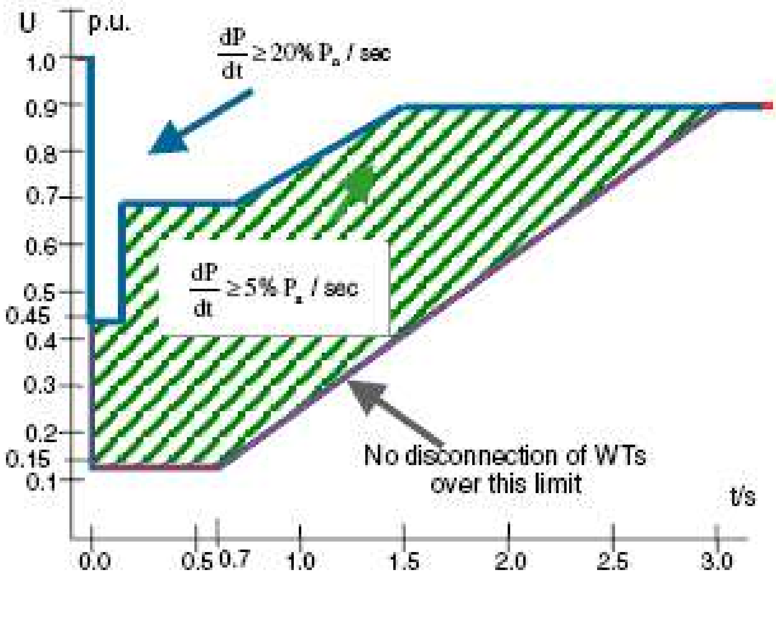



Figure 4.3 Voltage limits at grid connection point during and following network in Germany.

In a small band (see figure 4.3) of 10 % around the steady state voltage, no requirements are defined. In large *wind farms* reactive power is provided also by the cable capacitances and the shunt reactors used for compensation purposes.

A wind turbine (with voltage $\leq$ 100 kV) in **Denmark** must be designed to produce power at voltages and frequencies that differ from the rated values in the minimum times shown in figure 4.4. Voltages ( at the point of wind power connection) and frequencies for which the figure specifies time limited operation will occur less than 10 h/year. Abnormal voltages and frequencies must not result in a reduction of the production of more than 15 %.

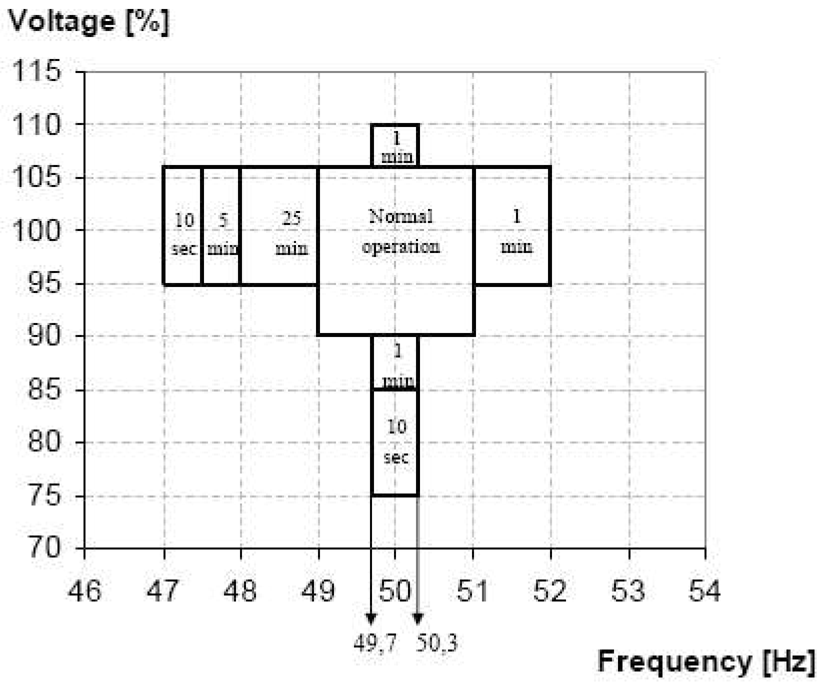



Figure 4.4 Design voltages and frequencies in Denmark.

The full load range indicates the voltage range within the wind farm in **Denmark** and shall be able to supply its nominal power.

### *IV.1.2Frequency control*

The frequency range is a requirement for the continuous operation and frequency control within acceptable limits to ensure the security of supply.

For **UK** the requirements for the frequency range in which power production units should stay on-line is for the values between 47.5 - 50.5 Hz and 47 - 47.5 Hz only during 20 seconds, for the frequency values 50.5 - 55 Hz it shall be a power output reduction of 2 % or 0.1Hz

It is required that generators stay connected to the **New Zealand** grid all the times when the frequency is above 47.5 Hz for North Island and 47 Hz for South Island. These requirements have been defined to ensure that the frequency of the grid is stable under any generation scenario.

In the case of **New Zealand**, it is potentially important that, with a large wind power penetration, *wind farm* output control is available so that the system operator is able to manage the grid effectively, especially during post fault events. Whether individual generators need to have output control provisions is an issue that requires further research.

For very high levels of wind penetration, a governing function may be required. Current wind generator technologies can support this, although it may be difficult to retrofit this technology for wind facilities not designed specifically for speed governing.

Renewable Energies Act generating units in **Germany** are exempt from the basic requirements of providing primary control power for the time being, even if the rated power is more than 100 MW. Wind energy plants are exempted from the basic requirement of being capable of operation under primary control.

When the frequency changes, the wind turbine's production (with voltage $\leq$ 100 kV) in **Denmark** must be regulated as specified in Table 4.3 and shown in figure 4.5.

The resolution on the setting of the set points in table 4.3 must be at least 10 mHz. In the frequency range 47 - 52 Hz the measuring error must not exceed ±10 mHz. This requirement must be met even if the sinusoidal voltage waveform is distorted.

A single instant phase shift of 20 degrees must not initiate any control action.

| | Setting range | Default Value |
|---|---|---|
| Lower frequency limit for the control range during under frequency ($f_n$) | 50 - 47 Hz | 48.7 Hz |
| Upper frequency range for the control range during over frequency ($f_u$) | 50 - 52 Hz | 51.3 Hz |
| Lower frequency limit for the dead band during under frequency ($f_{d-}$) | 50 - 47 Hz | 49.85 Hz |
| Upper frequency limit for the dead band during over frequency ($f_{d+}$) | 50 - 52 Hz | 50.15 Hz |
| Control factor for the production applying to frequencies in the range $f_n$ - $f_{d-}$ and $f_{d+}$ - $f_u$, see figure 4.4. (Control factor 1 means that the production is the maximum possible, or the power set point if this is specified) | Over frequency: $1 \quad \frac{f - f_d}{f_n - f_d}$ Under frequency: $1 \quad \frac{f - f_d}{f_n - f_d}$ | |
| Regulating speed calculated from exceeding a limit value to completed control action. | 10 % of the rated power per second | |

Table 4.3 Values applying to frequency control of production on Denmark.

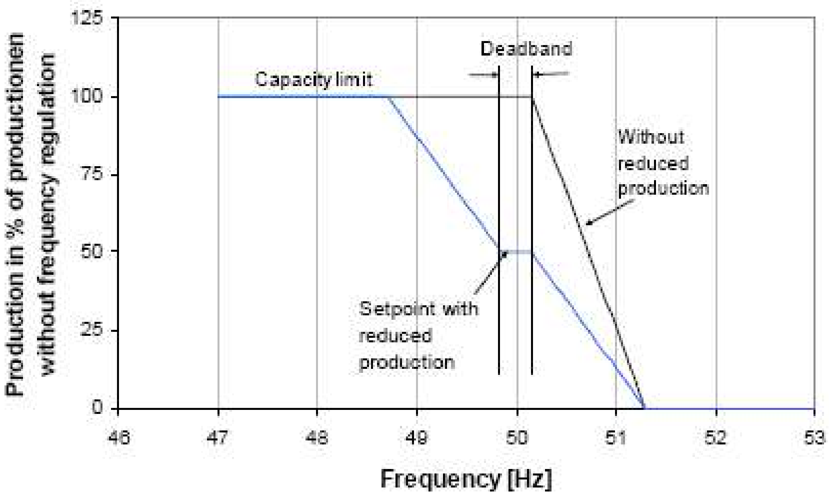


Figure 4.5 Frequency control base don the default values in table 4.3 on Denamrk.

By automatic frequency regulation the control equipment of the individual turbine in **Denmark** shall change the production depending on the gird frequency. Via the farm controller it shall be possible to set the total regulation characteristics of the wind farm.

### *IV.1.3Active and reactive power*

The main reason for the active power control for the wind power units is in order to ensure a stable frequency.

Consumption and generation of reactive power must be matched in order to maintain a stable system voltage. Continuously variable reactive compensation is usually provided by synchronous generators using their automatic voltage regulator equipment.

The electricity governance rules in **New Zealand** require that:

Generators must be able to export net reactive power equal to 50% of the maximum continuous MW output power when operating at full load;
Generators must be able to import net reactive power equal to 33% of the maximum continuous MW output power when operating at full load.

This effectively requires that generators are able to have a power factor of 0.9 for export and 0.95 for import.

The typical locations for the reactive power compensation within a wind plant in **USA** are:

At each individual turbine, dependent on the reactive power requirements and characteristics of the rotating machinery in the turbine.
At the interconnect substation in the form of switched shunt capacitor banks.
Al locations along the medium voltage collector lines depending on the layout of the plan.

Interconnection customer which is connected in to the **USA** grid shall design the large generating facility to maintain a composite power delivery at continuous rated power output at the point of interconnection at a power factor within the range of 0.95 leading to 0.95 lagging, unless the transmission provider has established different requirements that apply to all generators in the control area on a comparable basis. The objective of this standard is to ensure good voltage control on the grid. Wind technology is different from conventional technology, this regard in two ways:

*Wind plants* generally have large medium voltage collection grids whose design can significantly affect grid and turbine voltage control in and of itself.
Voltage control/reactive support for wind plants consists of multiple voltage control devices at the turbines (as for conventional technology) and, in addition, discrete voltage control devices whether static or dynamic or both distributed throughout the wind plant.

In the case of power injections from plants using renewable energy sources into the **German network** of the TSO, operating conditions may occur which can jeopardize system operation or damage operating equipment. It must then be possible to reduce power supply under any operating condition and from any working point to a maximum power value defined by the TSO. This reduction of active power output at the target value must be finalized within 10 minutes.

If the network frequency rises to a value of 50.25 Hz, the active power supplied shall be continuously reduced until it equals zero at 51.5 Hz. If the frequency deviation declines, active power supply shall be restored according to circumstances.

The *wind farm* in **Denmark** shall be equipped with reactive power compensation ensuring that the reactive power as a mean value over 10 seconds is kept within the control band as shown in figure 4.6.

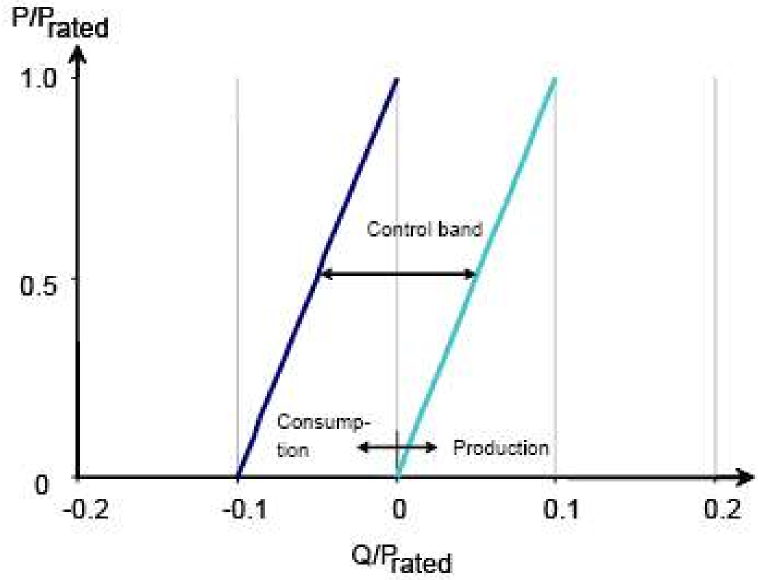



Figure 4.6 Requirements concerning a wind farms (in Denmark) exchange of reactive power with a grid (P: Active power, Q: Reactive power).

### *IV.1.4Quality*

*For wind farm* protection a relay protection system should be present to act in cases of high short circuit currents, under voltages and over voltages during and after the fault.

During the fault duration in the **German grid**, a short circuit current shall be injected into the network as described in *transient stability* (short circuits) and steady state stability (*power oscillations*).

A rapid voltage variation is defined as a single, rapid change in the RMS value of the voltage. The following requirements are made concerning the magnitude (d) of rapid voltage variations caused by a wind turbine in **Denmark** with voltage equal or less than 100 kV at the connection point:

10 - 20 kV grid, d 4 %.
50 - 60 kV grid, d 3 %.

Maximum permissible values for rapid voltage changes from the *wind farm* in **Denmark** in the connection point are:

General constrain < 3.0 %.
Unit frequency of 10 per hour < 2.5 %.
Unit frequency of 100 per hour < 1.5 %[11].

[11] Requeriments based on IEC 61000-3-7

If the *wind farm* in **Denmark** is isolated with a part of the power system, the *wind farm* shall not give rise over voltages which may damage the equipment in the power system.

The temporary over voltages, shall therefore be limited to 1.30 p.u. of the output voltage and be reduced to 1.20 p.u. of the output voltage after 100 ms, these voltages are the 50 Hz component.

The following requirements are made concerning the resulting *flicker* contribution $P_{lt}$ from wind turbines in **Denmark** connected at the same voltage level and to the same main substation:

10 - 20 kV grid, $P_{lt}$ 0.50
50 - 60 kV grid, $P_{lt}$ 0.35

The index (lt) refers to an observation period of two hours.

The flicker contribution[12] from the *wind farm* in **Denmark** in the connection point shall be limited so that:

$P_{st}$ < 0.30 determined as a weighted average of the flicker contribution over ten minutes.
$P_{st}$ < 0.20 determined as a weighted average of the flicker contribution over two minutes.

The index (st) refers to short term flicker.

The magnitude of harmonics in the current from a wind turbine in **Denmark** with voltage $\leq$ 100 kV, and generated by this, as well as the total contribution from wind turbines to the interharmonic voltages in the connection point must meet the requirements in tables 4.4 and 4.5

The requirements in the table are considered met if the interharmonic currents meet the requirements made for neighbouring harmonic currents with equal ordinals.

| Ordinal v | Harmonic voltage $U_v$ (%) |
|---|---|
| Unequal harmonics | |
| 5 | 3.0 |
| 7 | 2.5 |
| 11 | 1.8 |
| 13 | 1.5 |
| 17 | 1.0 |
| 19 | 0.8 |
| 23 | 0.8 |
| 25 | 0.8 |
| Equal harmonics | |
| 2 | 1.0 |
| 4 | 0.5 |
| 6 | 0.3 |
| 8 | 0.3 |
| 10 | 0.1 |
| > | 0.1 |

[12] Are define in IEC 61000-3-7

Table 4.4 Limit values for harmonic voltages in the 10 - 20 kV in the Danish grid.

| Frequency (Hz) | Maximum contribution to overtone voltages (%) |
|---|---|
| < 100 | 0.2 |
| 100 $\leq$ f < 2.5 | 0.5 |

Table 4.5 Limit values for interharmonic voltages in the 10 - 20 kV in the Danish grid.

The harmonic disturbance in the *wind farm* in **Denmark** shall be lower than 1 % for $1<n<51$ in the connection point and the total harmonic effective distortion shall be smaller than 1.5 %.

# V. Network conditions

Because of the deregularization process taking place in many countries, all of the participants that want to enter the electricity market must comply with the connection conditions set by their TSO.

## *V.1 Connection condition*

The electricity company in the **UK** shall ensure that plant and apparatus forming part of its transmission system is of such design and construction that its satisfactory operation will not be prevented by any variations. The company and the user may agree a greater or lesser variation in voltage at the connection point in relation to a particular connection site which will be recorded in the connection agreement and/or use of system agreement.

### *V.1.1 Safety and isolating devices*

In the **USA**, at the point of interconnection to the grid, an isolating device, which is typically a disconnector switch, shall provide physical and visible isolation from the applicant's facilities. Such devices shall:

Simultaneously open all phases (gang operated) to the connected facilities.
Be accessible by the electric company and may be under the electric company's system operator jurisdiction.
Be lockable in the open position by the electric company.
Not be operated without advance notice to either party, unless an emergency condition requires that the device be opened to isolate the interconnection facilities.
Be suitable for safe operation under the conditions of use.
.

The electricity company's personnel may lock the device in the open condition and install safety grounds if:

It is necessary for the protection of maintenance personnel when working on de-energized circuits.
The interconnected facility or the electricity company's equipment presents a hazardous condition.
The interconnected facility interferes with the operation of the electricity company's system
The electricity company's system interferes with the operation of the interconnected facility.

### V.1.2 Back up protection for grid faults

At some points of connection in **New Zealand**, a generator must ensure that its generating units have both main and back up protection systems for nearby faults on the grid, where the necessity for, and the method of providing, such protection systems is agreed between the system operator and the generator.

## V.2 Safety coordination

The **USA** electric system has been developed with careful consideration for system stability and reliability during disturbances. The type of connection, size of the load, breaker configurations, load characteristics, and the ability to set protective relays will affect where and how the point interconnection is made. The applicant may be required to participate in special protection schemes, called Remedial Action Schemes (RAS) such as generator dropping and load shedding.

## V.3 Supplies through balancing groups

The power station operator in **Germany** shall communicate to the responsible TSO:

Injection schedules (not relevant to accounting) of all power stations (related to the injection node) of a net maximum output capacity > 100 MW.

For all power stations, if several BGMs are supplied: the evolution in time of the distribution factors, or schedules of supplies to BGMs other than the one with the open contract. These schedules must be identical with those of the receiving BGMs.

In the verifiable event of forced outages of generating units with a net maximum output capacity of  5 MW, changes of schedules are possible (e. g. between balancing groups or control areas) at a 15 minutes lead time.

In the event of an unforeseen load reduction of > 5 MW (e. g. due to failure of equipment), its removal and re-commissioning of generating units after failures, changes of schedules are possible at a lead time of 60 minutes prior to the beginning of the schedule interval, on condition that adequate evidence is furnished. Evidence can also be produced subsequently.

## V.4 Operator conditions

For the required connections in extra high voltage in **Germany**, ENE is entitled to temporarily limit the network connection capacity or disconnect a system in the following cases:

Acts of God.
Potential risk to secure system operation.
Congestion or the risk of overloading systems components.
Risk of islanding.
Hazard to steady state or dynamic network stability.
Critical increase of frequency.
Unacceptable network interactions.
Maintenance, repair and construction works.

### V.4.1 Switchgear design and operation

No important element of the regional grid in **India** shall be deliberately opened or removed from service at any time, except when specifically instructed by RLDC or with specific and prior clearance of RLDC. In case of opening/ removal of any important element of the grid under an emergency situation, the same shall be communicated to RLDC at the earliest possible time after the event.

The switchgear shall be planned, installed and operated in **Germany** as “closed electric operating area” in accordance with the relevant regulations and the recognized rules of technology. The switchgear design should be:

Single station without switch connections (E-station), see figure 1 of Appendix B.
Single station with switch connection (ES-station), see figure 2 of Appendix B.
Station with single busbar (NE-station), see figure 3 of Appendix B.
Double busbar station (NE-station).
Double busbar station with in feed from the transmission network or a power station (NE-station).

Switchgear and switchgear components should be especially high voltage equipment, used by the connectee on the network connection. The personnel employed for the operation of the switchgear must be qualified. Only qualified electrical personnel and persons instructed in electrical regulations have access to the switchgear. A contact person of the connectee with switching authorization and responsibility for his system on the network connection must be at the disposal of ENE at any time.

### *V.4.2 Reactive power exchange and operation*

Reactive power compensation and/or other facilities in **India** should be provided by SEBs/STUs or distributing agencies as far as possible in the low voltage systems close to the load points, thereby avoiding the need for exchange of reactive power to/from ISTS and to maintain ISTS voltage within the specified range.

Line reactors may be provided to control temporary over voltage within the limits as set out in connection agreements. The addition of reactive compensation to be provided by the agency shall be indicated by CTU in the connection agreement for implementation.

## ***V.5 Neutral***

The neutral earthing in generating units in the **UK** should be at nominal system voltages of 132 kV and above the higher voltage windings of a transformer of a generating unit must be start connected with the star point suitable for connection to earth.

For the neutral earthing in transformers, the higher voltage windings of three phase transformers and transformer banks connected to the NGC transmission system must be star connected with the star point suitable for connection to earth.

The earthing and lower voltage winding arrangement shall be such as to ensure that the earth fault factor requirement will be met on the NGC transmission system at nominal system voltages of 132 kV and above.

Each TSO (high and extra high voltage) in **Germany** is responsible for the neutral point treatment of his components.

For low resistance neutral point earthing in the extra high voltage network:

First zone time protection for 100 % of all systems components (fault clearance times 150ms).
Circuit breaker failure protection system
Single phase automatic reclosure on overhead lines with a reclosure interval of 1.0 to 1.2 seconds.

For low resistance neutral point earthing in the high voltage network the protection concepts valid at ENE provided for the following criteria:

For transformers 100 % first zone time protection (fault clearance times 150 ms).
For lines an overlapping of the distance protection with three phase automatic reclosure with intervals from 0.4 to 0.8 seconds and subsequent triggering according to the time grading schedule if applicable.
Connecting of the transformers neutral points will have to be agreed with ENE even to the extent that the neutral point of the low voltages side will not always be available to the connectee.

### *V.6 Configuration*

In **USA** the operating procedures and equipment installation will determine the type of transition scheme implemented. For any installation, improper operation will result in action by the electric company to remove such hazard in order to safeguard its employees.

The possible transition operating schemes are listed below:

An isolated scheme is achieved by operating in a break before make switching scheme. This operation requires that the load will lose voltage before the generating unit is connected to the load. The generating unit will supply all of the needs of the connected load. See figure 4 in Appendix B.

A closed momentary parallel operating scheme operates in a synchronized make before break switching scheme. With this operation no loss of voltage to the connected load occurs. The momentary closed operation puts the generating unit in parallel with the electricity company's transmission system for a short time (usually less than 30 cycles.) The generating unit will supply all of the needs of the connected load. See figure 5 in Appendix B.

Closed continuously parallel scheme is accomplished by operating in a synchronized make switching scheme. The generating unit operates continuously in parallel with the electricity company's system. The generating unit can supply all or part of the connected load or supply capacity and energy to wholesale customers on the regional transmission grid. Closed continuously parallel generating units require separate generating metering. See figures 6 and 7 in Appendix B.

Parallel operation is defined as the operation of applicant-owned generation with output terminals connected directly or through an intermediary's system to the electricity company's delivery system. Parallel operation may be long term or momentary ("make before break," "hot" or "close transition transfer").

### *V.7 Equipment*

Within the power system in **India**, instantaneous values of system frequency and voltage are subject to variation from their nominal value. All agencies shall ensure that plant and apparatus requiring service from/to the ISTS is of such design and construction that satisfactory operation will not be prevented by such variation.

### *V.7.1 Design and requirements of equipment*

For the **USA** is as follows:

1) Isolation power transformer.

   To provide maximum operating flexibility for the applicant's generation and to minimize possible adverse effects on other electricity company's customers, a power transformer may be required between the applicant's generator and the electricity company's owned equipment. This transformer is usually connected to isolate the zero sequence circuit of the applicant from the zero sequence circuit of the electricity company's system. Upgrading of the electricity company's transformer insulation levels and lightning arrester ratings to a higher voltage may be required at the applicant's expense due to the addition of applicant's generation. This is required for all sizes. For units less than 1 MW, the transformer that provides isolation is likely to be the same one already serving customer load. For those units 1 MW or greater, it is likely that a dedicated transformer is added as part of the new unit.

2) Generation step up transformer.

   The electricity company shall determine which voltage taps would be suitable for a step up transformer for the applicants proposed project. Suitable taps are required to give the transformer the essential capacity for the generator to:

   Deliver maximum reactive power to the electricity company's system at the point of interconnection (generator operating at 90 % lagging power factor).
   Absorb maximum reactive power from the electricity company's system (generator operating at 90 % leading power factor).

3) Automatic generation control.

   To comply with NERC control performance criteria, the applicant generator shall be equipped with Automatic Generator Control ("AGC") equipment to permit remote control and enable the generation to be increased or decreased via automatic generation control.

For the **UK** all plant and apparatus at the connection point shall comply with the current IEC, BS, Euronorm and CENELEC requirements, for the items listed below, as modified by any ESI standard or specification:

Circuit breakers
Switch disconnectors
Disconnectors
Earthing devices
Power transformers
Voltage transformers
Current transformers
Surge arresters
Bushings
Neutral equipment
Capacitors

Line traps
Coupling devices
External insulation
Insulation co-ordination devices

Plant and apparatus shall be designed, manufactured and tested in premises certified in accordance with the quality assurance requirements of ISO 9001 or equivalent.

Regarding equipment design standards, primary substation equipment in **South Africa** shall comply with relevant IEC specifications. In case of equipment operated at transmission substations at voltage of 132 kV and below, the relevant participants may agree to use standards applicable to the distribution system.

For motorized isolators:

All 765 kV, 400 kV, 275 kV and 220 kV isolators at new substations shall be motorized.
Isolators of 132 kV and below shall be specified on individual merit in consultation with the relevant customer.

For transformer tap change.

Transformers using the transmission system at 220 kV and above are normally not on automatic tap changer. The Volts/Hertz of flux levels at the point of connection shall meet the requirements in table 5.1.

| Volts/Hertz (p.u.) | 1.1 | 1.125 | 1.15 | 1.175 | 1.2 | 1.225 | 1.25 | 1.275 | 1.3 |
|---|---|---|---|---|---|---|---|---|---|
| Time (seconds) | continuous | 3000 | 600 | 180 | 72 | 42 | 30 | 24 | 18 |

Table 5.1 Volts/Hertz connection requirements for South Africa

For the specification of thermal units and equipment requirements for **Denmark and Sweden**, 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, below 100 MW and above 25 MW.

For power units between 100 MW and 25 MW the regulations are the same as the specifications for thermal power units above 100 MW.

### *V.7.2 Synchronizers*

All applicants in the **USA**, independent of generation size classification, are responsible for synchronization to the electricity company's system. Before synchronization to the electricity company's system will be permitted, all required studies, tests, inspections, and contracts must be completed and approved. Any remote control that is required will be implemented through the telemetry equipment.

For the Synchronising facilities in **New Zealand** at a point of connection:

Asset owners, other than *grid owners*, must provide a means of checking synchronisation before the switching of assets, where it is possible that such switching may result in connection of parts of the New Zealand electric power system which are not synchronised.

*Grid owners* must provide a means of checking synchronisation before the switching of assets in locations agreed with the system operator so that it is not possible for such switching to result in connections of parts of the New Zealand electric power system which are not synchronised.

Any auto-reclose facility at the grid interface, where power flow into the grid can occur, must include an appropriate synchronising check facility.

## *V.8 HVDC (High voltage direct current)*

High voltage DC (HVDC) is used to transmit large amounts of power over long distances or for interconnections between asynchronous grids. When electrical energy is required to be transmitted over very long distances, it can be more economical to transmit using direct current instead of alternating current. For a long transmission line, the value of the smaller losses, and reduced construction cost of a DC line, can offset the additional cost of converter stations at each end of the line.

Since the power flow through an HVDC link is directly controllable, HVDC links are sometimes used within a grid to stabilize the grid against control problems with the AC energy flow.

In **Sweden and Denmark**:

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.
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.

In **India:**

All Extra high voltage sub-station equipments shall comply with Bureau of Indian Standards (BIS)/IEC/ prevailing code of practice.
All equipment shall be designed, manufactured and tested and certified in accordance with the quality assurance requirements as per IEC/BIS standards.
Each connection between an agency and ISTS shall be controlled by a circuit breaker capable of interrupting, at the connection point, the short circuit current as advised by CTU in the specific connection agreement.

## *V.9 Demand control*

In the **UK** this customer demand management means either reducing the supply of electricity to a customer or disconnecting a customer in a manner agreed for commercial purposes between a supplier and its customers. These procedures are listed below:

1) Each network operator will organize its user system and make such arrangements as are necessary so that a 6 % reduction of voltage supplied to all customers on its user system can be imposed following an instruction from the company.

2) Each network operator will arrange that the total demand on its system (less the demand of certain customers, the existence and level of which is subject to prior approval by the company), is arranged in groups of 5 % of total demand (based on winter peak value) so that any or all such groups can be disconnected when the company instructs the network operator to so do.

3) Each network operator with a customer demand in excess of 10 MW will arrange for the provision of automatic low frequency disconnection in stages by tripping relays of at least 40 % of the total demand (based on winter peak value) of its customer(s), in order to seek to limit the consequences of the loss of a major source of generation or an event on the transmission system which leaves part of the total system with a generation deficit.

4) Each network operator will make such arrangements as are necessary to enable it, at the company's instruction, to disconnect customers under emergency conditions irrespective of frequency.

# VI. Frequency

## *VI.1 Connections conditions*

Very early AC generating schemes used arbitrary frequencies based on convenience for steam engine, water turbine and generator design. Once induction motors became common, it was important to standardize frequency for compatibility with the customer's equipment. Standardizing on one frequency also, later, allowed interconnection of generating plants on a grid for economy and security of operation.

The frequency of the electrical system varies by country; most electric power is generated at either 50 or 60 Hz, this chapter deals with the requirements and standards for frequency support.

The maximum allowable *dead band* shall be 0.15 Hz for governing for units in **South Africa** contracted for instantaneous reserve and 0.5 Hz for units not contracted instantaneous reserve. Coal fired units not equipped with a *dead band* facility shall have a droop of 10 % or less. If the desired response from coal fired units is 5 % of MCR sent out at 49.75 Hz, then this is equivalent to a 10 % droop with no *dead band*.

For **Sweden and Denmark:**

For the operational characteristics in the thermal power units, the minimum output power shall be as low as possible, 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. The overload capacities should only be utilized to a certain limit, because of reductions in the efficiency and/or the life time of the unit. The unit including auxiliary equipment should be designed to utilize these overload capacities up to 2 h/day and up to 500 h/year. No overload capacity is specified for nuclear power units.

*House load operation*.

1) All power units shall be designed to change over safely to *house load operation* frequency from range 51 - 53 Hz and frequency below 47.5 Hz, and for large voltage disturbances.
2) Power step change for nuclear, subsequent power response rate, spinning disturbance reserve and island operation are not relevant to small power stations.
3) For tolerance to frequency variations, the voltage profile as shown in figure 6.1, 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 6.2 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.

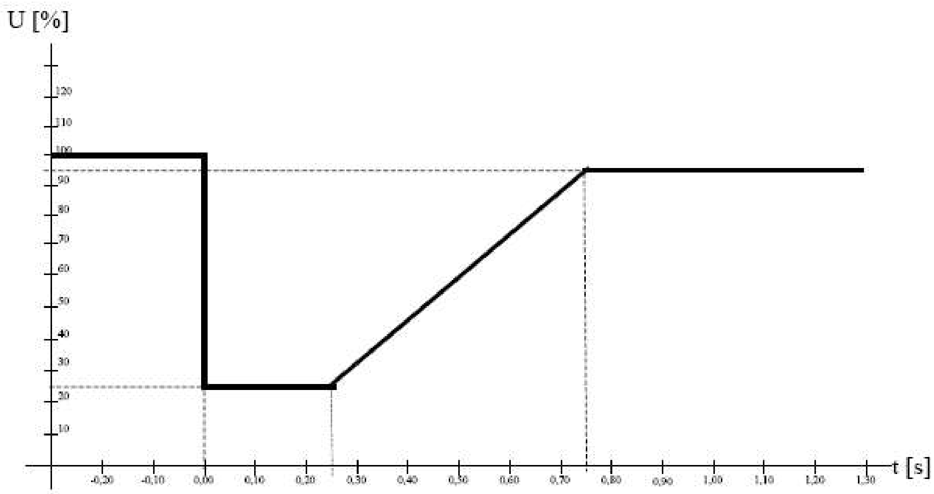



Figure 6.1 Voltage profile tolerance for thermal power units in Denmark and Sweden.

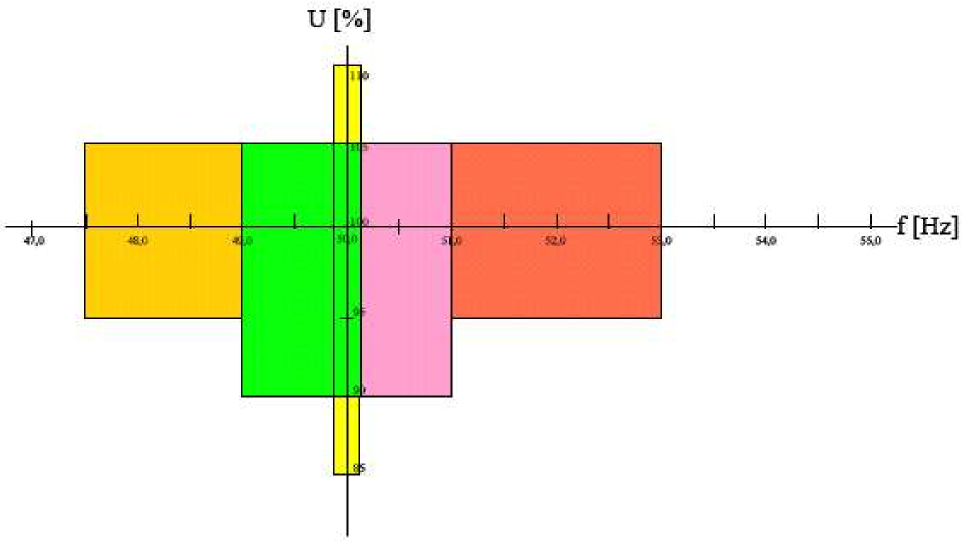



Figure 6.2 voltage and frequency range to avoid tripping of power stations in Denmark and Sweden.

### *VI.1.1Frequency support*

An **UK** CCGT generating unit must be capable of continuously supplying its rated active power output within the system frequency range 49.5 - 50.5 Hz. Any decrease of output power occurring in the frequency range 49.5 - 47 Hz should not be more than in proportion with frequency.

Statutory limits as defined by electricity regulations are 50 0.5 Hz except in abnormal or exceptional circumstances when the frequency could rise to 52 Hz or fall to 47 Hz, plant should continue to operate in this range.

For output and operation at off nominal frequency, each generating unit should be able to maintain its maximum active power output down to 49.5 Hz and thereafter any reduction in power output should be no more than proportionately with frequency i.e. a minimum output of 95 % of rated at 47 Hz.

The first criterion ensures that should there be a primary generating loss then there is no secondary loss of output as the frequency is controlled to the statutory limits, and as a consequence caps the size of the loss for which reserve must be held and hence the cost to the electricity supply industry of reserve provision. The second criterion forms a baseline against which the system can be designed to operate in emergency conditions. If this characteristic is not met then there is an increased risk that, in such an event, the power system would not return to a stable operating condition.

In the **UK** the frequency of the NGC transmission system shall be nominally 50 Hz and shall be controlled within the limits of 49.5 - 50.5 Hz unless exceptional circumstances prevail.

Each generating unit and/or CCGT module must be capable of:

> Active power output for system frequency changes within the range 50.5 to 49.5 Hz.
> Maintaining its active power output at a level not lower than the figure determined by the linear relationship shown in figure 6.3 for system frequency changes within the range 49.5 - 47 Hz, such that if the system frequency drops to 47 Hz the active power output does not decrease by more than 5 %.

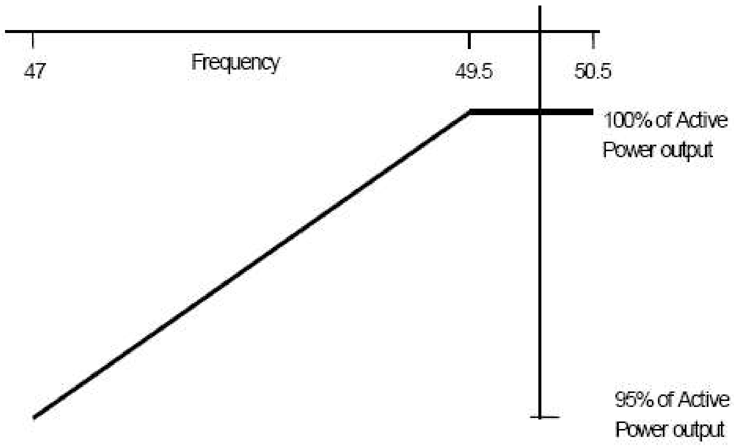



Figure 6.3 Tolerances for active power output for UK.

In **South Africa**, the nominal frequency is 50 Hz within (49.5 - 50.5 Hz). The design of the turbo alternator units must enable continuous operation, at up to 100 % active power output.

In **Germany** the frequency is in the range of 49.5 - 50.5 Hz.

The permissible variation in **Sweden and Denmark** of the frequency during normal state is between 49.9 and 50.1 Hz. And the deviations of frequency and voltage system below 25 MW within the hatched area on figure 6.2 should not be allowed to 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.

For Tolerance to frequency variations in all the units, it shall be possible to operate all the units 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 h/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 6.2.

For power systems above 110 kV, 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 - 50.1 Hz.

As for the requirements regarding frequency response, they shall be a minimum of 6,000 MW/Hz for the synchronous system throughout the frequency range of 49.9 - 50.1 Hz. The requirement regarding the frequency response is distributed between the subsystems in accordance with last year's annual consumption.

In **India**, the rated frequency of the system shall be 50.0 Hz and shall normally be controlled within the limits as per Indian Electricity Rules, 1956 as amended from time to time.

All regional constituents in **India** shall make all possible efforts to ensure that the grid frequency always remains within the 49.0 - 50.5 Hz band, the frequency range within which steam turbines conforming to the IEC specifications can safely operate.

One of the main objectives of the **New Zealand** system operator is to ensure that the frequency is in range according to the levels seen in table 6.1 for the North and South Islands.

| Frequency band (Hertz) (where "x" is the frequency during a **momentary fluctuation**) | Maximum number of occurrences by period (commencing on and from the **operational date**) |
|---|---|
| $52 > x \geq 51.25$ | 7 in any 12 month period |
| $51.25 > x \geq 50.5$ | 50 in any 12 month period |
| $49.5 \geq x > 48.75$ | 60 in any 12 month period |
| $48.75 \geq x > 48$ | 6 in any 12 month period |
| $48 \geq x > 47$ | 1 in any 60 month period |

Table 6.1 Frequency range for New Zealand

### *VI.1.2Speed governors*

For the speed control of an **UK** CCGT plant, each generating unit should have a fast acting proportional speed governor to ensure satisfactory high speed control and to enable the provision of response for which the generating unit operator may derive an ancillary service payment. The governor functional design standard is stated and a nominal overall droop of 4 % is required to ensure speed control below 52 Hz in the event of an islanding condition. A minimum *dead band* of 0.01 5 Hz is specified and a facility to alter the target frequency to 50 0.1 Hz in steps of 0.05 Hz is required in order that NGC can control electric time error nominally within 10 seconds. Although at present the minimum response is not stated, a minimum primary response to low frequency of about 15 % of maximum output and a minimum secondary response of 8 % are generally recommended.

All units connected in the **South Africa** power system above 50 MVA shall have an operational governor. Tripping times in the range 47.5 - 48.5 Hz shall be agreed with TSO.

Each generating unit in **India** shall be fitted with a turbine speed governor having an overall droop characteristic within the range of 3 - 6 % which shall always be in service.

The protection requirements for **India's** generating units are as follows:

1) All generating units, which are synchronized with the grid, irrespective of their ownership, type and size, shall have their governors in normal operation at all times. If any generating unit of over 50 MW size (10 MW for north eastern region) is required to be operated without its governor in normal operation, the RLDC shall be immediately advised about the reason and duration of such operation. All governors shall have a droop of between 3 % and 6 %.

2) Facilities available with/in load limiters, automatic turbine run up system, turbine supervisory control, coordinated control system, etc. shall not be used to suppress the normal governor action in any manner. No *dead bands* and/or time delays shall be deliberately introduced.

3) Each generating unit shall be capable of instantaneously increasing output by 5 % for a minimum of 5 minutes, when the frequency falls and when operating at any loading up to 105 % MCR.

4) All generating units, operating at/up to 100 % of their MCR shall normally be capable of (and shall not in any way be prevented from) instantaneously picking up 5 % extra load for at least 5 minutes or within technical limits prescribed by the manufacturer when frequency falls due to a system contingency. The generating units operating at above 100 % of their MCR shall be capable of (and shall not be prevented from) going at least up to 105 % of their MCR when frequency falls suddenly. Any generating unit of over 50 MW size (10 MW for NER) not complying with the above requirement, shall be kept in operation (synchronized with the regional grid) only after obtaining the permission of RLDC. However, the constituent can make up the corresponding short fall in spinning reserve by maintaining an extra spinning reserve on the other generating units of the constituent.

5) The recommended rate for changing the governor setting, i.e. supplementary control for increasing or decreasing the output (generation level) for all generating units, irrespective of their type and size, would be one 1 % per minute or as per manufacturer's limits. However, if frequency falls below 49.5 Hz, all partly loaded generating units shall pick up additional load at a faster rate, according to their capability.

The protection requirements for **New Zealand's** generating units are:

1) Each of its generating units has a speed governor which provides stable performance with adequate damping; and has an adjustable droop over the

range of 0 - 7 %; and does not adversely affect the operation of the grid because of any of its non-linear characteristics.

2) Appropriate speed governor settings to be applied before commencing system tests for a generating unit are agreed between the system operator and the generator. The performance of the generating unit is then assessed by measurements from system tests and final settings are then applied to the generating unit before making it ready for service after those final settings are agreed between the system operator and the generator. Asset owners will not change speed governor settings without system operator approval.

### *VI.1.3Special requirements*

In the **UK** testing of frequency response capabilities, as shown in figure 6.4, are measured by taking the responses as obtained from some of the dynamic response tests specified by NGC and carried out by generators for compliance purposes and to validate the content of ancillary services agreements using an injection of a frequency change to the plant control system (i.e. governor and load controller). The injected signal is a linear ramp from 0 - 0.5 Hz frequency change over a 10 second period, and is sustained at 0.5 Hz frequency change thereafter, as illustrated in figures 6.5 and 6.6.

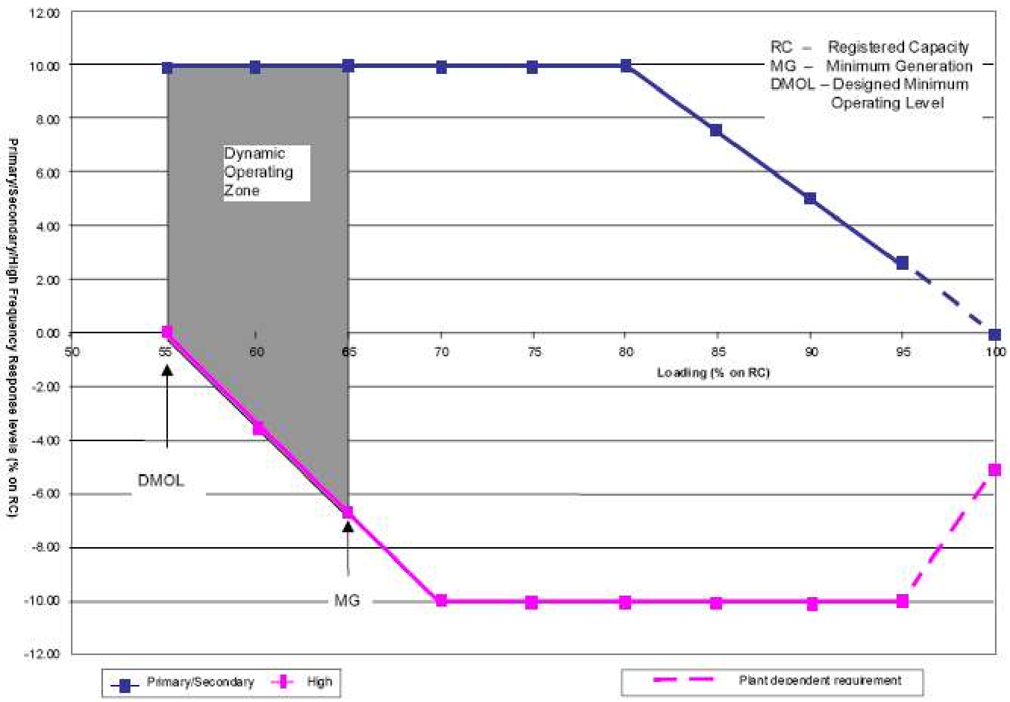



Figure 6.4 Minimum Frequency Response Requirement Profile for a 0.5 Hz frequency change from Target Frequency in UK.

The primary response capability (P) of a generating unit or a CCGT module is the minimum increase in active power output between 10 and 30 seconds after the start of the ramp injection. The secondary response capability (S) of a generating unit or a CCGT module is the minimum increase in active power output between 30 seconds and 30 minutes after the start of the ramp injection as illustrated in figure 6.5.

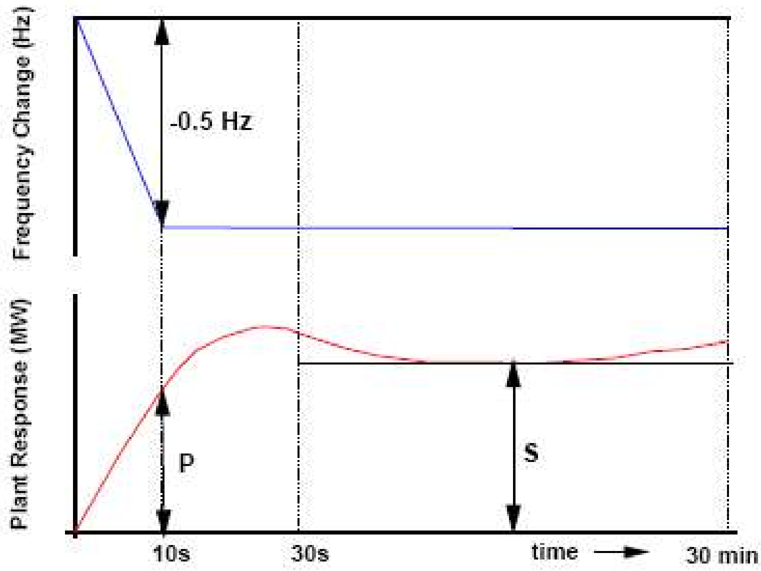



Figure 6.5 Interpretation of Primary and Secondary Response Values for UK.

The high frequency response capability (H) of a generating unit or a CCGT module is the decrease in active power output provided 10 seconds after the start of the ramp injection and sustained thereafter as illustrated in figure 6.6.

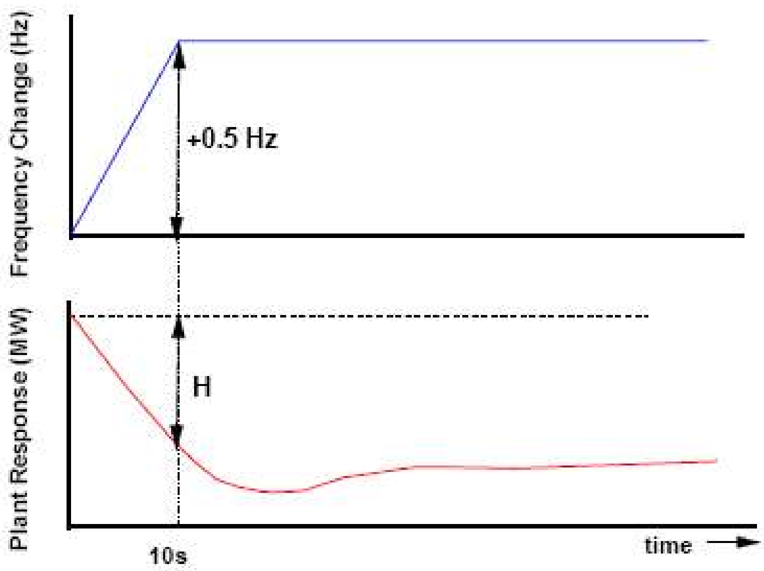



Figure 6.6 Interpretation of high frequency response values for UK.

Generators will be responsible for protecting all their generating units against damage, if frequency excursions outside the range 52 - 47 Hz should occur.

Applicant generating equipment in **USA** must have short term capability for non-islanded low frequency operation not less than the following:

60.0 - 59.5 Hz, continuous
59.5 - 59.3 Hz, 10 minutes
59.3 - 58.7 Hz, 10 seconds

To ensure “ride through” capability of the electriity company’s system, the applicant shall implement an under frequency relay set point for the facility no greater than 58.5 Hz. Interconnected generating facilities receiving power from the electric company’s system may implement a higher under frequency relay set point if necessary to protect their facilities and equipment.

The TSO in **Germany** shall take measures to ensure not only secure transmission of the maximum projected load for this network, but also transmission of the primary and secondary control power and minutes reserve power. The transmission capacity and infrastructure maintained in the transmission system shall thus be determined by the following tasks:

- Transmission of the projected maximum load.
- Transmission of the primary control, secondary control and minutes reserve power.

### *VI.2 Frequency control process*

A local disturbance may cause quick and widespread response from the rest of the system, causing system-wide oscillations or other stability problems. The effect of a disturbance may propagate and amplified through the network, resulting in cascading outages of various elements in the network. Control devices are installed and appropriate settings are made in the design stage to mitigate possible disturbances.

Frequency control is an important aspect of power system operation. It is an indication of power balance between total generation and total load in the system. Frequency deviation (whether it is 50 or 60Hz) requires immediate actions to balance supply and demand of electricity. There are limitations on generator response.

Reserves and the ability of the system to respond to frequency variation are mentioned below.

The quality of system frequency control on the **UK** grid system is managed by the NGC as the grid operator through instructions to individual generating units for energy commitment, frequency response and reserves, and through a partnership role with Scottish power and Scottish hydro electric.

For frequency control each generating unit must meet the following minimum requirements:

- Fast acting proportional speed governor to provide continuous, automatic and stable response across its entire operating range.
- Speed governor capable of being set to a droop of 3 - 5 %.
- Minimum speed governor *dead band* no greater than 0.03 Hz.
- Load control capability with target frequency setting of 50   1Hz either continuously or in 0.05 Hz steps.
- Capability to control frequency to below 52 Hz in island operation.
- If operating at full load, capability to maintain power output if frequency falls to 49.5 Hz, thereafter a reduction in power output no more than proportionately with frequency down to 47 Hz.

For the control arrangements, each generating unit must be fitted with a fast acting proportional turbine speed governor and unit load controller or equivalent control device to provide frequency response under normal operational conditions.

A facility to modify, so as to fulfil the requirements of the balancing codes, the target frequency setting either continuously or in a maximum of 0.05 Hz steps over at least the range 50 0.1 Hz should be provided in the unit load controller or equivalent device.

> In particular, other control facilities, including constant reactive power output control modes and constant power factor control modes (but excluding VAR limiters) are not required.

The **UK** system frequency could rise to 52 Hz or fall to 47 Hz in exceptional circumstances. Design of generator's plant and apparatus must enable operation of that plant and apparatus within that range in accordance with table 6.1.

| Frequency | Range requirement |
|---|---|
| 47.5 - 52 Hz | Continuous operation is required. |
| 47 - 47.5 Hz | Operation for a period of at least 20 seconds is required each time the frequency is below 47.5 Hz. |

Table 6.1 Generator operation frequency in UK.

Generators will be responsible for protecting their generating units against the risk of any damage which might result from any frequency excursion outside the range 52 - 47 Hz and for deciding whether or not to interrupt the connection between his plant and apparatus and the transmission system in the event of such a frequency excursion.

The company requires that 40 % of demand can be tripped in stages using relays which can be set in the range 47.6 - 48 Hz.

In general, power system disturbances initiated by system events such as faults and forced equipment outages; these events expose the system to oscillation in voltage and frequency. It is important that generators and lines remain in service for dynamic (transient) oscillations that are stable and damped.

For frequency control in **USA** when communications with the system operations control center has been lost, the constant frequency operating guide shows the operation expected from all plant operators during major frequency excursions. The operator will respond following this guide to the maximum ability of the applicants generating equipment. See Figure 6.7.

1. Use this guide *only* when AGC and all voice communications with System Control have been lost.
2. When frequency is in C zone, manually load/unload unit as soon as possible.
3. When frequency is in B zone, manually load/unload unit in gradual increments to avoid overcorrecting.
4. When frequency is in A zone, let governor action control unit output.
5. Raise or lower kV set point no more than ± 5% of schedule if necessary in order to increase MW capability.
6. In situations of severe under/over speed or severe under/over voltage,

**TAKE STANDARD PRECAUTIONS TO PROTECT YOUR UNIT!**

| | Shaft Speed (RPM) | | |
|---|---|---|---|
| Freq. (Hz) | 2-poles | 4-poles | _-poles |
| 59.80 | 3588 | 1794.0 | |
| 59.90 | 3594 | 1797.0 | |
| 59.95 | 3597 | 1798.5 | |
| 60.00 | 3600 | 1800.0 | |
| 60.05 | 3603 | 1801.5 | |
| 60.10 | 3606 | 1803.0 | |
| 60.20 | 3612 | 1806.0 | |

Frequency = ½ (no. of poles) x (RPM/60)

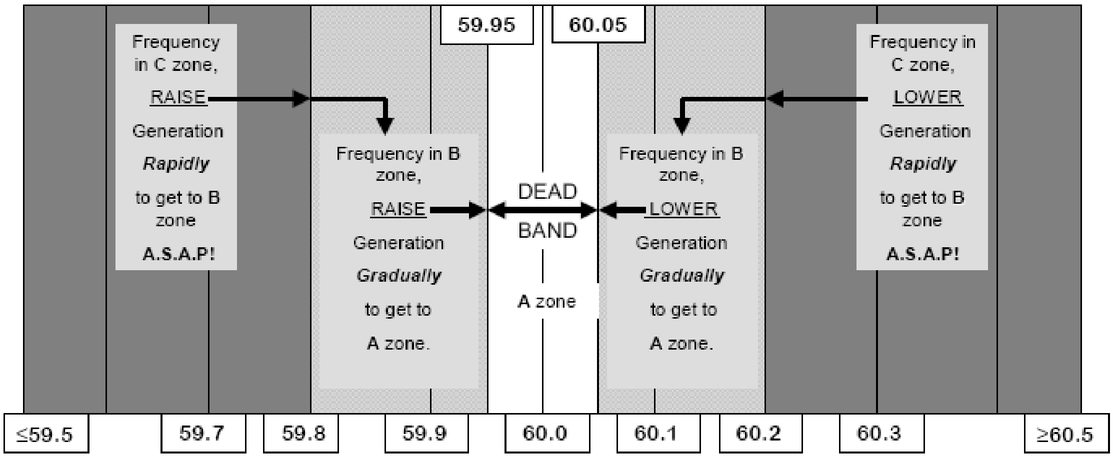



Figure 6.7 Constant frequency operating guide in U.S.A.

In the **USA** when system frequency declines, loads are automatically interrupted in steps occurring at 59.3, 59.0 and 58.7 Hz respectively, in attempts to stabilize the system by balancing the generation and the load. It is important that generators and lines remain connected to the system during frequency declines, both to limit the amount of load shedding required and to help the system avoid a complete collapse.

For **Sweden and Denmark:**

> 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.
> There should be an aim to keep the time deviation **Δ**T within the time range of ±30 seconds. The time deviation shall be corrected during quiet periods with high frequency response and with a moderate frequency deviation.

The control systems for new HVDC interconnections between **Sweden and Denmark** should be adapted so that the risk of multiple commutation failures in the event of dimensioning fault is minimized.

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.

For automatic frequency control for hydro units in **Sweden and Denmark**, 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 unit controller shall have an adjustable frequency turbine regulator set point in the range from 49.9 - 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.

Restoration of the frequency and the interchange power in the **German grid** to the set point value must begin within 30 seconds at the latest, and must be completed within 15 minutes.

All TSOs shall supply each other with the following values online for continuous monitoring of the quality of control:

The measured values of the active power on their interconnecting lines.
The instantaneous total system deviation of their secondary controllers.
The control block leader shall supply the values for the German control block.

The quality of control should be checked in the case of major control deviations by measurement and evaluation of the parameters stated in the primary control in the event of generator and consumer failures > 600 MW.

Where new installations are commissioned or existing installations replaced, the following parameters must be observed:

Accuracy: 0.5 - 1.5 % for the individual active power measurements; 1.0 - 1.5 mHz for the frequency measurements.
Cycle time for measurement: 0.1 - 2 seconds.
Cycle time of the secondary controller: 0.1 - 2 seconds.

In **New Zealand**, the contributions to frequency support in the case of under-frequency events are as follows:

1) HVDC owner.

The HVDC owner will at all times ensure that, while connected, its assets contribute to supporting frequency during an under frequency event in either island by:

Remaining connected to those assets making up the grid in the North and South Islands while the frequency in both islands remains above 48 Hz.

Remaining connected to those assets making up the grid in the North and South Islands while the frequency in both islands remains below 48 Hz and above 47 Hz for 90 seconds.

Remaining connected to those assets making up the grid in the North and South Islands while the frequency in both Islands remains above 45 Hz for 35 seconds, unless the frequency in either Island is less than 46.5 Hz and the frequency is falling at a rate of 7 Hz per second or greater.

Subject to the level of transfer and the HVDC link configuration at the beginning of the under frequency event, if the HVDC link itself is not the cause of the under frequency event, modifying the instantaneous transfer on the HVDC link by up to 250 MW with the objective of limiting the difference between the North and South Island frequencies to no greater than 0.2 Hz.

### *VI.2.1Response to low frequency*

When the under frequency limit is reached in **New Zealand** and the frequency continues to fall, generators must use reasonable endeavours to take the following immediate independent action to assist in restoring frequency:

Increase the energy injection from generating units where those generating units are physically capable of increasing such injection.

Attempt to restore grid frequency to the normal band by synchronising, connecting to the grid and loading those generating units which are not connected but are able to be connected and operated in this manner.

Re-synchronise, re-connect to the grid and load any generating units that have tripped and are able to be connected and operated in this manner.

Report to the system operator as soon as possible after taking correction actions.

In **New Zealand**, the contributions to frequency support in the case of under frequency events are as follows:

1) Generators.

Subject to the exceptions for the south island generators, each generator will at all times ensure that, while connected, its assets, other than any excluded generating stations, contribute to supporting frequency by remaining synchronised, ensuring each of its generating units can and does, at a minimum, sustain pre-event output:

At all times when the frequency is above 47.5 Hz.

For at least 120 seconds when the frequency is 47.5 Hz.

For at least 20 seconds when the frequency is 47.3 Hz.

For at least 5 seconds when the frequency is 47.1 Hz.

For at least 0.1 seconds when the frequency is 47.0 Hz.

2) Exceptions for South Island generators.

South island generators will ensure that each of their assets, other than excluded generating units, remains synchronised, and can and does, at a minimum, sustain pre-event output:

At all times when the frequency is above 47 Hz.

For 30 seconds if the frequency falls below 47 Hz but not below 45 Hz.

3) North Island distributors and South Island grid owners

North Island distributors and South Island grid owners will ensure that they have established and maintained automatic under frequency load shedding in block sizes and with relay settings in accordance with the requirements of the technical codes.

4) Injections.

Each generator (while synchronised) and the HVDC owner will at all times ensure that their assets, other than any generating units within an excluded generating station, make the maximum possible injection contribution to maintain frequency within the normal band (and to restore frequency to the normal band). Any such contribution will be assessed against the technical codes.

For the **UK** figure 6.4 shows the minimum frequency response requirement profile diagrammatically for a 0.5 Hz change in frequency. The percentage response capabilities and loading levels are defined on the basis of the registered capacity of the generating unit or CCGT module. Each generating unit and/or CCGT module must be capable of operating in a manner to provide frequency response at least to the solid boundaries shown in the figure. If the frequency response capability falls within the solid boundaries, the generating unit or CCGT module is providing response below the minimum requirement which is not acceptable.

The frequency response delivered for frequency deviations of less than 0.5 Hz should be no less than a figure which is directly proportional to the minimum frequency response requirement for a frequency deviation of 0.5 Hz. For example, if the frequency deviation is 0.2 Hz, the corresponding minimum frequency response requirement is 40 % of the level shown in figure 6.4. The frequency response delivered for frequency deviations of more than 0.5 Hz should be no less than the response delivered for a frequency deviation of 0.5 Hz.

Each generating unit and/or CCGT module must be capable of providing some response in keeping with its specific operational characteristics, when operating between 95 and 100 % of registered capacity, as illustrated by the dotted lines in figure 6.4.

At the minimum generation level, each generating unit and/or CCGT module is required to provide high and low frequency response depending on the system frequency conditions. Where the frequency is high, the active power output is therefore expected to fall below the minimum generation level.

The designed minimum operating level is the output at which a generating unit and/or CCGT module has no high frequency response capability. It may be less than, but must not be more than, 55 % of the registered capacity. This implies that a generating unit or CCGT module is not obliged to reduce its output to below this level unless the frequency is at or above 50.5 Hz.

The low frequency relays to be used in the **UK** shall be in accordance with the requirements of the bilateral agreement. They should have a setting range of 47.0 - 50 Hz and be suitable for operation from a nominal AC input of 63.5, 110 or 240 V. The following general parameters on the requirements of approved low frequency relays for automatic installations is given as an indication, without prejudice to the provisions that may be included in a bilateral agreement:

Frequency settings: 47 - 50 Hz in steps of 0.05 Hz or better, preferably 0.01 Hz.
Measurement period within minimum selectable settings: Settings range of 4 to 6 cycles.
Operating time: Between 100 and 150 ms dependent on measurement period setting.
Voltage lockout: Selectable within a range of 55 - 90 % of nominal voltage.
Facility stages: One or two stages of frequency operation.
Output contacts: Two output contacts per stage to be capable of repetitively making and breaking for 1000 operations.

Each network operator will make arrangements that will enable automatic low frequency disconnection of at least 60 % of its total peak demand (based on annual average cold spell conditions[13]), in order to seek to limit the consequences of a major loss of generation or an event.

For the **UK** low frequency relay initiated response from generating units, the company may utilise centrally despatched generating units with the capability of low frequency initiated response as:

Synchronisation and generation from standstill.
Generation from zero generating output.
Increase in generated output.
Reduction in pumping load to zero.

In establishing its operating margin, generators shall comply with company instructions for low frequency relay settings. Generators shall not alter low frequency relay settings or take low frequency relay initiated response out of service without company agreement, except on safety grounds (relating to personnel or plant) and shall inform the company immediately.

For **South Africa:**

For low frequency requirements for hydro alternator units, if the system frequency falls below 46 Hz for more than 1 second it can be islanded or tripped to protect the unit.

For low frequency requirements for turbo alternator units, the units shall be designed to be capable of a minimum response of 3 % of MCR sent out within 10 seconds of a frequency drop over the range from minimum load to 97 % of MCR sent out. The response shall be sustained for at least 10 minutes.

Also for low frequency turbo alternator units and in a range from 48.5 - 48.0 Hz, the unit shall be designed to run for at least 10 minutes over the life of the plant if the frequency goes below 48.5 Hz but greater than 48.0 Hz. The unit shall be able to operate for at least 1 minute while the frequency is in this range. If the system frequency is less than 48.5 Hz for 1 minute the unit can be islanded or tripped to protect the unit.

When there is low frequency in the range 48.0 to 47.5 Hz, the unit shall be designed to run for at least 1 minute over the life of the plant if the frequency goes below 48.0 Hz but is greater than 47.5 Hz. If the system frequency is less than 48.0 Hz for 10 seconds the unit can be islanded or tripped to protect the unit.

If the system frequency falls below 47.5 Hz for longer than 6 seconds the unit can be islanded or tripped to protect the unit. The unit that is capable of automatically starting within 10 minutes shall have automatic under frequency starting.

For low frequency hydro units in **Sweden and Denmark** and in the range from 49 - 47.5 Hz, it shall be possible to operate the unit under disturbance conditions for 30 minutes 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.

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

[13] A particular combination of weather elements which gives rise to a level of peak demand within an NGC financial year which has a 50% chance of being exceeded as a result of weather variation alone.

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.

In **India**, all regional constituents shall provide automatic under frequency load shedding in their respective systems, to arrest frequency decline that could result in a collapse/disintegration of the grid, as per the plan separately finalized by the concerned REB forum, and shall ensure its effective application to prevent cascade tripping of generating units in case of any contingency. All Regional constituents shall ensure that the under frequency load shedding/islanding schemes are functional. However, in case of extreme exigencies, under frequency relays may be temporarily kept out of service with prior consent of RLDC. RLDC shall promptly inform REB about the locations at which these relays are temporarily out of service. RLDC shall also inform REB about instances when the desired load relief is not obtained through these relays in real time operation.

REB shall carry out periodic inspection of the under frequency relays and maintain proper records of the inspection.

### *VI.2.2Response to high frequency*

Regarding high frequencies for the hydro units in **Sweden and Denmark** with transitory frequency variations from 51 - 52 Hz, it shall be possible to operate the unit for 5 seconds 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.

If the frequency range is from 51 - 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 minutes.

For **South Africa:**

For high frequency requirements for turbo alternators, the response shall be fully achieved within 10 seconds and shall be sustained for the duration of the frequency excursion. The unit shall respond to the full designed minimum operational.

For high frequency requirements for hydro alternators, the unit shall be designed to run for at least 5 seconds over the life of the plant if the frequency goes above 54 Hz, hence the turbo alternator units must be able to operate for at least 1 second in this range. If the system frequency increases to 54 Hz for longer than 1 second the unit can be islanded or tripped to protect the unit.

Also for high frequency turbo alternator units, with over frequency conditions in the range from 51.5 - 52 Hz, the unit shall be designed to run for at least 10 minutes over the life of the plant if the frequency goes above 51.5 Hz but is less than 52 Hz. If the system frequency is greater than 51.5 Hz for 1 minute and the unit is still generating power it can be islanded or tripped to protect the unit.

For over frequency conditions in the range above 52 Hz, the unit shall be designed to run for at least 1 minute over the life of the plant if the frequency is above 52 Hz. If the system frequency is greater than 52 Hz for 10 seconds and the unit is still generating power it can be islanded or tripped to protect the unit.

When the over frequency limit is reached in **New Zealand**, and the frequency continues to rise, generators must use reasonable endeavours to take the following immediate independent action to assist in restoring frequency:

Decrease the energy injection from connected generating units where generators are physically capable of decreasing such injection.

Report to the system operator as soon as possible after taking correction actions.

The required response to high frequency from synchronized genset[14] in the **UK** is as follows:

1) Each synchronised genset in respect of which the generator has been instructed to operate so as to provide high frequency response, which is producing active power and which is operating above designed minimum operating level, is required to reduce active power output in response to an increase in system frequency above the target frequency (or such other level of frequency as may have been agreed in an ancillary services agreement). The target frequency is normally 50 Hz.

2) The rate of change of active power output with respect to frequency up to 50.5 Hz shall be in accordance with the provisions of the relevant ancillary services agreement with each generator.

3) The reduction in active power output by the amount provided for in the relevant ancillary services agreement must be fully achieved within 10 seconds of the time of the frequency increase.

4) In addition to the high frequency response provided, the genset must continue to reduce active power output in response to an increase in system frequency to 50.5 Hz or above at a minimum rate of 2 % of output per 0.1 Hz deviation of system frequency above that level, such reduction to be achieved within five minutes of the rise to or above 50.5 Hz. For the avoidance of doubt, the provision of this reduction in active power output is not an ancillary service.

If plant operation is below minimum generation:

1) All reasonable efforts should in the event be made by the generator to avoid such tripping, provided that the system frequency is below 52 Hz.

2) If the system frequency is at or above 52 Hz, the requirement to make all reasonable efforts to avoid tripping does not apply and the generator is required to take action to protect the generating units.

If the **UK** system frequency rises to or above 50.4 Hz, each generator at each generating plant shall ensure that each of its generating units has responded in order to contribute to containing and correcting the high system frequency. Generating unit output shall be reduced at a minimum rate of 2 % of generating unit output per 0.1 Hz deviation of system frequency above 50.4 Hz.

Any such reduction in output shall be made without delay and without receipt of despatch instructions from the company. Generators shall continue to operate their generating plant in this manner until either the system frequency has returned to below 50.4 Hz or until otherwise instructed by the company.

[14] A generating unit or CCGT module at a large power station

### *VI.2.3Response from generator units*

When a generating unit or CCGT module in the **UK** has responded to a significant frequency disturbance, its response capability must be fully restored as soon as technically possible. Full response capability should be restored no later than 20 minutes after the initial change of system frequency arising from the frequency disturbance.

Response from gensets:

> Each genset must at all times have the capability to operate automatically so as to provide response to changes in frequency.
> Each synchronised genset producing active power must operate at all times in a limited frequency sensitive mode (unless instructed in accordance with frequency sensitive mode below to operate in frequency sensitive mode.)

Regarding existing gas cooled reactor plant; NGC will permit these plants other than frequency sensitive units to operate in limited frequency sensitive mode at all times.

As to frequency sensitive mode:

1) NGC may issue an instruction to a genset to operate so as to provide primary response and/or secondary response and/or high frequency response (in the combinations agreed in the relevant ancillary services agreement). When so instructed, the genset must operate in accordance with the instruction and will no longer be operating in limited frequency sensitive mode, but by being so instructed will be operating in frequency sensitive mode.

2) Frequency sensitive mode is the generic description for a genset operating in accordance with an instruction to operate so as to provide primary response and/or secondary response and/or high frequency response (in the combinations agreed in the relevant ancillary services agreement).

A System frequency induced change in the active power output of a genset which assists recovery to target frequency must not be countermanded by a generator except where it is done purely on safety grounds (relating to either personnel or plant) or, where necessary, to ensure the integrity of the power station .

For the **UK**, control arrangements are as follows:

1) Each generating unit must be capable of contributing to, in a manner satisfactory to the company, frequency and voltage control by modulation of active power and reactive power supplied to the transmission system or a user system.

2) Each generating unit must be fitted with a fast acting proportional turbine speed governor to provide power and frequency control under normal operational conditions. Where a generating unit becomes isolated from the rest of the total system but is still supplying customers, the speed governor must also be able to control system frequency between 47.5 and 52 Hz.

3) A continuously acting fast response automatic excitation control system is required to control the generating unit voltage without instability over the entire operating range of the generating unit.

4) On load tap changing facilities are required on generating unit transformers for despatch of reactive power.

For automatic response from generating plants:

1) All centrally despatched generating units must be capable of operating at all times in an automatic frequency sensitive mode. All synchronised centrally despatched generating units will operate at all times in an automatic frequency sensitive mode unless relieved of the obligation by the company.

2) The company may give express permission for centrally despatched generating units to operate in a frequency insensitive mode on occasions with due regard to the frequency sensitive capability available from the remaining synchronised centrally despatched generating units.

3) A system frequency induced change in the active power output of centrally despatched generating units which assists the recovery to target frequency must not be overridden by a generator except where it is done purely on safety grounds (relating to personnel or plant).

When national grid company determines it is necessary to take action to control system frequency it will issue target frequency despatch instructions to the company in order to regulate system frequency within limits set out in the Electricity Supply Regulations 1988.

The target frequencies shall normally be 49.95, 50.00 and 50.05 Hz or as otherwise agreed.

A variation in target frequency shall be made by steps of 0.05 Hz. Only one variation of target frequency may be made in any period of 30 minutes.

The change of output power of a thermal power unit in **Sweden and Denmark** 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 - 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 - 8 %. The normal operation is generally with setting in the range from 4 - 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.*

In the **USA**:
For 10 MW or less:

All applicants generating equipment shall be designed to operate between 59.5 and 60.5 Hz. The operating frequency of the applicants generating equipment shall not deviate more than 0.5 Hz from a 60 Hz base.
For the detection of an island condition, generators must have a means of automatically disconnecting from the electricity company's system within 0.2 seconds if the frequency cannot be maintained within 0.5 Hz.
In the case where the generator is connected in parallel and provides regulation service, the applicants shall adhere to the frequency control requirements for units larger than 10 MW, as detailed below.

For 10 MW or greater:
The applicant will operate its generator consent with the electricity company's guidelines and requirements concerning frequency control. Generators shall be equipped with governors that sense frequency (unless exempt under NERC, MISO, or applicable reliability council rules due to prime mover or regulatory limitations).

Governors shall provide a 0 - 10 % adjustable setting nominally set at 5 % droop characteristic and a ± 0.036 Hz dead band unless otherwise agreed to by the electric company.

The generator must begin increasing or decreasing capability at frequency set points of 59.964 or 60.036 Hz respectively.
The change in capability must begin occurring within 0.5 seconds of a detected frequency disturbance.

Unless the electricity company agrees otherwise, if the generator is operated in parallel with the electric company's distribution system, the generator will provide appropriate relaying to detect an island condition and provide a means to automatically disconnect from the electric company's system within 0.2 seconds if the frequency cannot be maintained within 0.5 Hz.

### *VI.2.4Control reserve*

The supervisory authorities of **Denmark and Sweden** have appointed special system operators who are comprehensively responsible for the satisfactory operation of each subsystem.

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

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 (**Δ**f = 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 during the previous year. 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.

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.

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.

Fast active disturbance reserve, consists of gas turbines, thermal power, hydropower and load shedding. In round figures, Svenska Kraftnät 1,200 MW, Elkraft system 600 MW (where 300 MW is slow active disturbance reserve which, on special occasions, can be made fast.

Slow active disturbance reserve is active power available after 15 minutes.

In **Sweden and Denmark** 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).

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

Generally within UCTE, for that reason in **Sweden and Denmark** 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.

For thermal plants below 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 - 53 Hz.

The categories of operating reserve for the **UK** are as follows:

1) Primary response: the automatic response to frequency changes released increasingly with time over the period 0 to 10 seconds from the time of frequency change and fully available by the latter and which is sustainable for at least a further 20 seconds.

2) Secondary reserve: the automatic response to frequency changes which is fully available by 30 seconds from the time of frequency change to take over from the primary response and which is sustainable for at least 30 minutes.

3) Five minute reserve: That component of the operating reserve which is fully available within 5 minutes from the time of frequency change or despatch instruction pursuant to SDC2 and which is sustainable for a period of 4 hours.

The amount of operating reserve held by the company will be determined by allocation formulae set out in the British grid systems agreement.

Contingency reserve is reserve over, and above, operating reserve, allocated to cover:

Generation output shortfalls.
Demand estimation errors.
Differences between the instantaneous peak demand and the half hour integrated value.

The amount of contingency reserve will be determined by the company in line with system conditions.

The TSOs in **Germany** shall be obliged to observe the times for schedule value changes meticulously. It shall deploy minutes reserve power in the event of large imbalances between generation and consumption and/or for the restoration of a sufficient secondary control band.

Consumers can also participate in secondary control power and minute reserve provision by way of the controllable loads.

### VI.2.5Primary control

The entire UCTE, in **Sweden and Denmark**, 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

The primary control power to be maintained by **Germany** according to the UCTE coefficients shall be coordinated within the DVG, and should be maintained must be activated at an almost frequency deviation of 200 mHz, the power generated must be reduced by the primary control power which is to be maintained.

The neutral zone which results for each control area must be kept as low as possible and under all circumstances below ±10 mHz. The primary control reserve to be maintained by each control area must be able to be activated within 15 seconds at the latest in the event of a disturbance $\Delta P < 1500$ MW, and on a linear scale between 15 and 30 seconds at a $\Delta P$ between 1500 and 3000 MW (In accordance with UCTE).

The system performance must be examined and evaluated continuously in the event of generator and consumer failures > 600 MW.

Each generating unit with a nominal capacity 100 MW must be capable of supplying primary control power. This is a requirement for connection to the network.

Generating units with a nominal capacity < 100 MW may also be employed for assurance of primary control by agreement with the TSO.

All generating units in **Germany** complying with the necessary technical and operational requirements can participate in providing primary control power, secondary control power and minute reserve.

### VI.2.6Secondary control

The secondary control power in **Germany** may be used only for compensation of the instantaneous total system deviation. It may not for example be used to reduce the inadvertent energy exchange, or for other forms of compensation.

# VII. Voltage and reactive power

Transmission level voltages are usually considered to be 115 kV and above. Lower voltages such as 66 kV and 33 kV are usually considered sub-transmission voltages but are occasionally used on long lines with light loads. Voltages less than 33 kV are usually used for distribution. Voltages above 230 kV are considered extra high voltage and require different designs compared to equipment used at lower voltages.

## *VII.1 Connection conditions*

For **Sweden and Denmark** the voltage limits can be seen in tables 7.1 and 7.2, the information in the tables 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.

Tolerance to voltage variations in systems below 25 MW is not required observed. But a quick startup 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. Generator and voltage regulator characteristics, *house load operation* and verification are not required.

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.

Regarding the tolerance to voltage variations in the thermal and hydro units:

> For grid voltage range 90 - 105 % of normal voltage, it shall be possible to operate the unit continuously at full load within the frequency range of 49 - 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. A maximum operating time of 10 h/year and duration of 30 minutes maximum per case can be assumed within the frequency range of 50.3 - 51 Hz. See figure 6.2.
>
> For grid voltage range from 85 - 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, and an output power reduction of up to 10 % of full output may then be acceptable.
>
> For grid voltage range from 105 - 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. A small output power reduction may then be acceptable (approximately 10 %).
>
> 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.

| | 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 380 kV | 380 - 420 kV |
| Swedish thermal power | 1/3 at U>95% $U_{gen}$ [3] | 0 at U<105% $U_{gen}$ [3] | 395 - 420 kV |
| Finnish thermal power | cos φ = 0.9 at 420 kV [2] | cos φ = 0.95 at 420 kV [2] | 380 - 420 kV |
| Swedish hydro power | 1/3 at U>95% $U_{gen}$ [3] | -1/6 at U<105% $U_{gen}$ [3] | 395 - 420 kV |
| Finnish hydro power | cos φ = 0.9 at 420 kV [2] | cos φ = 0.95 at 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 voltage measured at the generator terminals.

Table 7.1 Mvar requirements for power plants in Sweden and Denmark

| | |
|---|---|
| Nominal continuous operating voltage on any bus for which equipment is designed. | $U_N$ |
| Maximum continuous voltage on any bus for which equipment is designed Note: To ensure voltages never exceed $U_M$, the highest voltage used at sending end busbars in planning studies should not exceed 0.98 $U_M$. | $U_M$ |
| Minimum voltage on PPC during motor starting | 0.85 $U_N$ |
| Maximum voltage change when switching, capacitors, reactors etc. (system healthy) | 0.03 $U_N$ (healthy) |
| Statutory voltage on bus supplying customer for any period longer than 10 consecutive minutes (unless otherwise agreed in supply agreement). | $U_N$ + or -5 % |

Table 7.2 Voltage limits for planning purposes for Sweden and Denmark

At outages above 110 kV, the voltage at the customer's connection point is below 1 % of the nominal voltage.

Voltage range in **New Zealand** for:

1) *Grid Owner*

   Each *grid owner* will ensure that its assets at and in between:

   The high voltage terminals of the *grid owner's* transformers are at each grid injection point and grid exit point.

   Where no transformer exists, the relevant grid injection point or grid exit point; are capable of being operated within the range of voltages of table 7.3.

| Nominal grid voltage (kV) | Voltage Limits | | | |
|---|---|---|---|---|
| | Minimum (kV) | | Maximum (kV) | |
| 220 | 198 | -10.0 % | 242 | 10.0 % |
| 110 | 99 | -10.0 % | 121 | 10.0 % |
| 66 | 62.7 | -5.0 % | 69.3 | 5.0 % |
| 50 | 47.5 | -5.0 % | 52.5 | 5.0 % |

Table 7.3 Voltage range operation in New Zealand

2) Generators

   Each generator with a point of connection to the grid will at all times ensure that its assets are capable of being operated, and do operate, when the grid is operated within the voltage range.

3) Distributors.

   Each distributor will ensure that its local network is capable of being operated, and does operate, when the grid is operated over the voltage range.

When either the minimum voltage limit or the maximum voltage limit set out in the table above is exceeded at any point of connection, generators and ancillary service agents must use reasonable endeavours to take immediate independent action to return the voltage to, as close as practicable, within such limits. Generators must use reasonable endeavours to synchronise, connect to the grid and, as necessary, load and adjust all available generating units which can assist in restoring the voltage. Ancillary service agents must also use reasonable endeavours to connect to the grid and, as necessary, load all available reactive capability resources, which can assist in restoring the voltage. As soon as corrective actions are taken, generators and ancillary service agents must report to the system operator on the action taken to correct voltage.

The following provisions shall apply to all generating units in **Germany** connected to the 380/220 kV network or to the 110 kV network. To be connected to the transmission system (380/220 kV or 110 kV), generating units need to satisfy basic technical requirements.

Voltage Characteristics in **Germany** in function to the different networks:

| | |
|---|---|
| 380 kV network: | 350 - 420 kV |
| 220 kV network: | 193 - 245 kV |
| 380 kV network: | 96 - 123 kV |

The upper value can be exceeded for up to 30 minutes. Because of pollution layers or the other effects, continuously deviating values may apply to the lower voltage value in the 110 kV network.

Voltage conditions at the point of connection in **South Africa**:

A voltage deviation in the range of 90 - 110 % of nominal voltage.
A three phase voltage drop to 0 for up to 0.2 seconds, to 75 % for 1 second, or to 85 % for 60 seconds provided that during the 3 minute period immediately following the and of the 0.2, 2, or 60 second period the actual voltage remains in the range 90 - 110 % of the nominal voltage.
Unbalance between phase voltages of not more than 3 % negative phase sequence and/or the magnitude of one phase not lower than 5 % than any of the other two for 6 hours.
A Volt/Hz requirement of less than 1.1 p.u.

In the **UK** the NGC transmission system at nominal system voltages of 132 kV and above is designed to be earthed with an earth fault factor of below 1.4. Under fault conditions the rated frequency component of voltage could fall transiently to 0 on one or more phases or rise to 140 % phase to earth voltage. The voltage rise would last only for the time that the fault conditions exist. The fault conditions referred to here are those existing when the type of fault is single or two phase to earth.

For connections to the NGC transmission system at nominal system voltages of below 132 kV the earthing requirements and voltage rise conditions will be advised by NGC as soon as practicable prior to connection.

All regional constituents in **India** shall make all possible efforts to ensure that the grid voltage always remains within the operating range of table 7.4.

| Voltage - (kV rms) | | |
|---|---|---|
| Nominal | Maximum | Minimum |
| 400 | 420 | 360 |
| 220 | 245 | 200 |
| 132 | 145 | 120 |

Table 7.4 Operating voltage range in India

The variation of voltage in **India** may not be more than the voltage range specified in the Indian Electricity Rules, 1956 as amended from time to time.

The agency engaged in sub-transmission and distribution shall not depend upon the ISTS for reactive support when connected. The agency shall estimate and provide the required reactive compensation in its transmission and distribution network to meet its full reactive power requirement, unless specifically agreed to with CTU.

### *VII.1.1Active power*

The active power output at the **UK** generating unit terminals under steady state conditions should not be affected by voltage changes in the normal operating range. The reactive power output at the generating unit terminals under steady state conditions and at rated active power should be fully available within the range ±5 % of nominal grid system voltage at the connection point.

In **Germany**, connecting generator with rated power of more than 50 MVA by the connectee is only permissible following approval by ENE.

Each generating unit must be capable of operating with reduced power output and continuous power changes of 1 % of the rated power per minute across the entire range between minimum power and continuous power.

With frequencies above the bold line in figure 7.1, is not permitted to reduce active power output even if the generating unit operated at rated power.

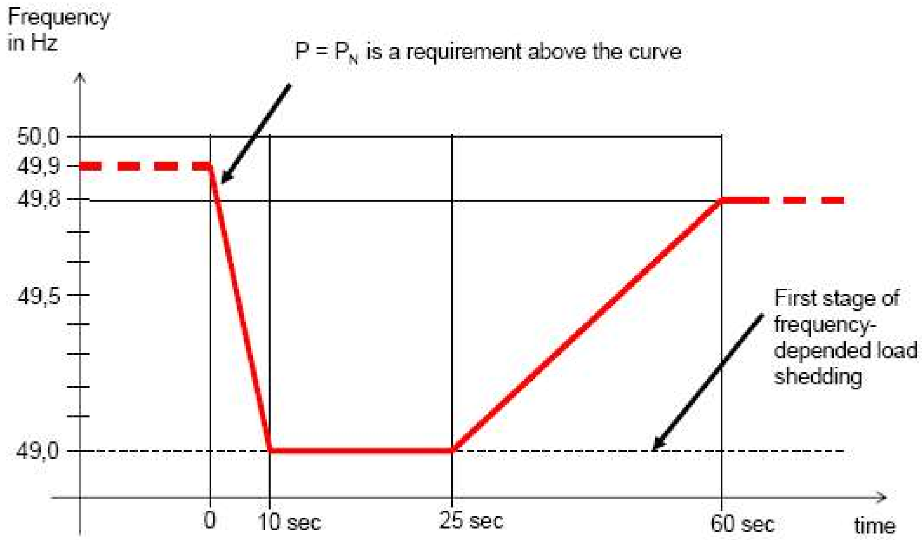



Figure 7.1 Frequency envelopes where no restriction of the active power output is allowed in Germany.

In an AC transmission line, the inductance and capacitance of the line conductors can be significant. The currents that flow in these components of transmission line impedance constitute reactive power, which transmits no energy to the load. Reactive current flow causes extra losses in the transmission circuit. The fraction of total power flow which is resistive (as opposed to reactive) power is the power factor.

Utilities add capacitor banks and other components throughout the system to control reactive power flow for reduction of losses and stabilization of system voltage, countries have different requirements regarding these issues, some of them are mentioned below.

### *VII.1.2Reactive power*

The reactive power output under steady state conditions in **UK** should be fully available within the voltage range ±5 % at 400 kV, 275 kV and 132 kV and lower voltages.

In **Denmark and Sweden** for reactive power output at low voltages, thermal power units shall be equipped with 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 seconds, in conjunction with network disturbances and at a generator busbar voltage of 70 % of the rated generator voltage.

In **Sweden and Denmark**, 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. See table 7.1 for MVA requirements for the power plants.

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.

Each generator in **New Zealand** with a point of connection to the grid will at all times ensure its assets:

1) Exporting net reactive power at full load. The required voltage range when exporting net reactive power can be seen in table 7.5.

| Nominal grid voltage (kV) | Voltage range for which reactive power is required | | | |
|---|---|---|---|---|
| | Minimum (kV) | | Maximum (kV) | |
| 220 | 198 | -10.0 % | 242 | 10.0 % |
| 110 | 99 | -10.0 % | 121 | 10.0 % |
| 66 | 62.7 | -5.0 % | 69.3 | 5.0 % |
| 50 | 47.5 | -5.0 % | 52.5 | 5.0 % |
| 33 | 31.35 | -5.0 % | 34.65 | 5.0 % |
| 22 | 21.45 | -2.5 % | 22.55 | 2.5 % |
| 11 | 10.725 | -2.5 % | 11.275 | 2.5 % |

Table 7.5 Reactive power voltage range (exporting) in New Zealand

2) Importing net reactive power at full load. The required voltage range when exporting net reactive power can be seen in table 7.6.

| Nominal grid voltage (kV) | Voltage range for which reactive power is required. | | | |
|---|---|---|---|---|
| | Minimum (kV) | | Maximum (kV) | |
| 220 | 209 | -5.0 % | 242 | 10.0 % |
| 110 | 104.5 | -5.0 % | 121 | 10.0 % |
| 66 | 62.7 | -5.0 % | 69.3 | 5.0 % |
| 50 | 47.5 | -5.0 % | 52.5 | 5.0 % |
| 33 | 31.35 | -5.0 % | 34.65 | 5.0 % |
| 22 | 21.45 | -2.5 % | 22.55 | 2.5 % |
| 11 | 10.725 | -2.5 % | 11.275 | 2.5 % |

Table 7.6 Reactive power voltage range (importing) in New Zealand

3) Support voltage in order to prevent system collapse.

For reactive supply and voltage control in the **USA** from generation source service, 10 MW or larger:

> Any generator providing such service to the control area operator must be able to automatically control the voltage level by adjusting the machine's power factor within a continuous range of 90 % power factor based on the station's sum total name plate generating capability. The voltage set point that the generator needs to maintain will be established and adjusted as necessary by the company's electric system operation department.
> The voltage control response rate (for synchronous generators, the exciter response ratio) is the speed with which the voltage-controlling device reacts to changers in the system voltage. The minimum response rate for a static excitation system shall have the exciter attain 95 % of the exciter ceiling (maximum) voltage in 0.1 seconds. The exciter ceiling voltages shall be at least two times the exciter voltage at the rated full load value. For rotary exciters, the exciter response ratio shall be at least 2.0. The response ratio, ceiling voltage, and speed of response are defines in IEEE 421.2 1990.
> Those generating applicants choosing to provide reactive supply and voltage control from generation sources service must coordinate with existing voltage regulation devices. In most cases, this will be a concern for those generators connecting to voltage regulated distribution facilities (12.5 kV and below).

The applicant's equipment in the **USA** shall not cause excessive voltage excursions. The applicant shall provide an automatic means of disconnecting its equipment from the company's electric system within three seconds if the steady state voltage cannot be maintained within the required tolerance.

Each new generating unit in **Germany** to be connected with a nominal capacity of PN 1,000 MW must meet the requirements shown figures 7.2a or 7.2b at the system point of connection. For generating units with PN > 1,000 MW, reactive power supply shall be agreed separately.

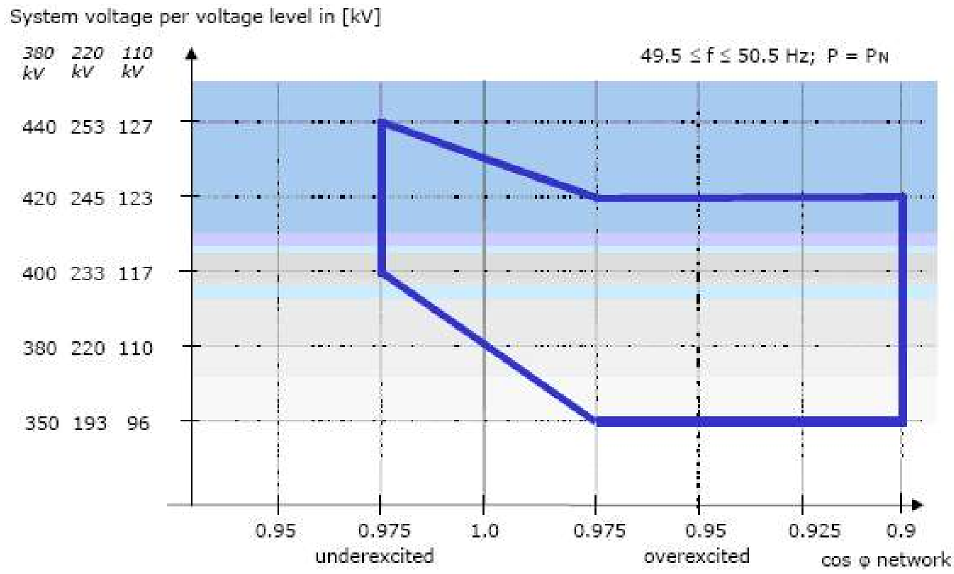



Figure 7.2a Basic requirement upon network-side reactive power supply generating units to the German network (variant 1).

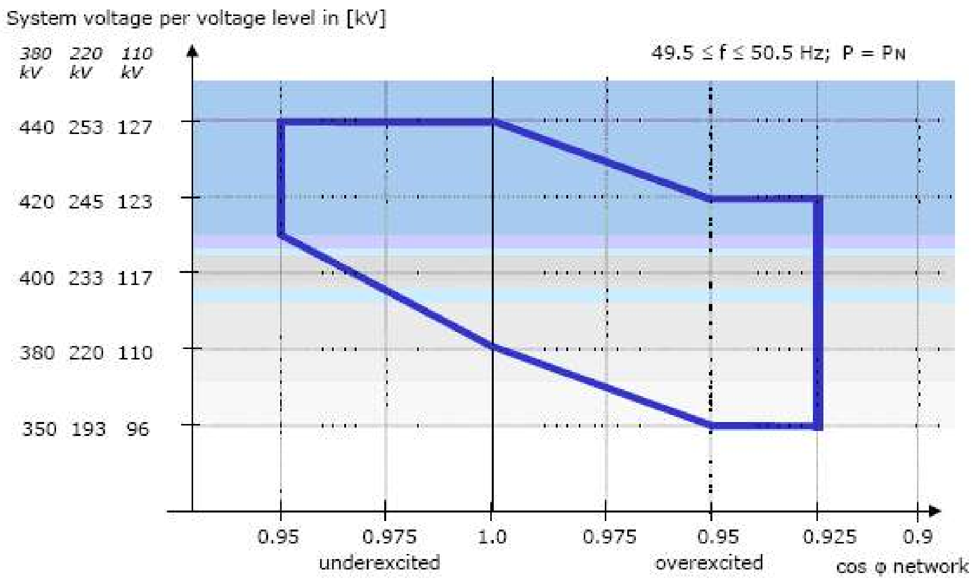



Figure 7.2b Basic requirements upon network-side reactive power supply of generating units to the German network (variant 2).

The generating unit must be able to move through the agreed reactive power range within a matter of minutes; this process must be repeatable indefinitely. If required, the system operator may place additional requirements upon the generating unit.

With active power output of  100 MW must meet the range of reactive power provision shown in figure 7.3 as a basic requirement at the network connection point.

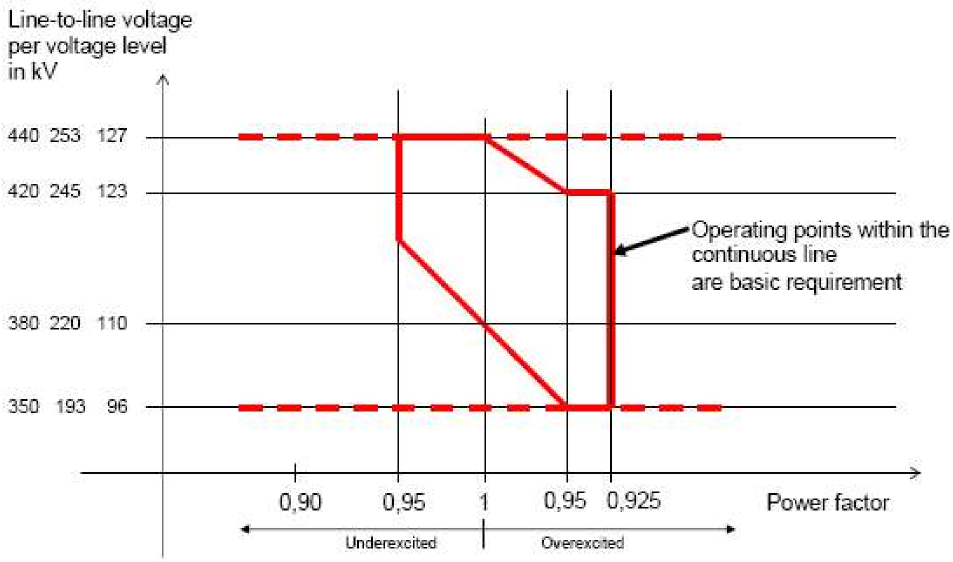



Figure 7.3 Requirements on the reactive power provision of a generating unit at frequencies between 49.5 and 50.5 without restriction of the active power output in Germany.

When changing the reactive power output, step changes corresponding to a reactive power of more than 2.5 % of the network connection capacity in the high voltage network and 5 % in the extra high voltage network are not permissible. No step changes smaller than 500 kvar will be required.

### *VII.1.3Reactive capabilities*

Regarding reserve capabilities, prior to the introduction of an **UK** CCGT plant, NGC had come to expect steam plant loaded at 75 % to offer an increase in output of approximately 15 % of plant rating within 10 seconds in response to a frequency reduction of 0.5 Hz over the 10 second period. A survey of CCGT in 1996 indicated that the offered response for primary reserve to be below 10 %.

#### VII.1.3.1 Power response capability during normal operation of the thermal power system

All condensing units in **Sweden and Denmark** 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 be capable of accommodating power changes without intervals by $\pm$2 % of full output within periods of 30 seconds. 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 $\pm$2 %.

Oil 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 %.

Coal fired units shall be designed for a power response rate of at least $\pm$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 %.

PWR nuclear power units shall be designed for a power response rate of at least $\pm$5 % of full power per minute within the output range of 60 - 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.

BWR nuclear power units shall be designed for a power response rate per minute of at least $\pm$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.

#### VII.1.3.2 Power response capability during power system disturbances

The demand from the power system in **Sweden and Denmark** is that the instantaneous power response shall be available within 30 seconds after a sudden frequency drop to 49.5 Hz. Half of that power response shall be available within 5 seconds after the frequency drop.

Fossil filled 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 seconds after the frequency drop. Units without or with only one re-heater shall be designed in such a manner that this power step will be accommodated within 30 seconds. If a unit includes more than one re-heater, a further delay corresponding to the time constants of such additional re-heaters is acceptable.

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 seconds.

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.

### *VII.1.4Power factor*

In **Germany** when the load flows from the ENE network to the connectee, the connectee shall adhere a power factor of cos $\boldsymbol{\phi}$ = 0.95 (inductive), connecting the generator with rated power of more than 50 MVA by the connectee is only permissible following approval by ENE with active reactive power output of < 100 MW to be operated with a power factor of cos$\boldsymbol{\phi}$ = 0.95 (inductive) to cos$\boldsymbol{\phi}$ = 0.95 (capacity) at the network connection point in.

All **UK** generating units must be capable of supplying rated active power output at any point between the limits 0.85 power factor lagging and 0.95 power factor leading at the generating unit terminals, unless otherwise agreed by the company. The short circuit ratio of the generating units shall be not less than 0.5 unless otherwise agreed by the company.

In the **USA** some portions of the electricity company's power system are in or adjacent to areas where other power suppliers (municipal or co-ops) utilize "ripple" load management systems. These systems employ an on/off keyed carrier signal (typically in the range of 150 - 400 Hz) injected into the power systems to address applicant site load management devices. Installation of shunt capacitor banks, as may be required for power factor correction of induction machines, or for providing capacitive output capability, may cause degradation of the ripple signal strength due to shunting to ground of the ripple signal through the capacitor bank(s). To prevent such degradation, appropriate tuned blocking filters may be required.

1) Substation specific power factor requirements.

   The company's electric system is designed and operated assuming the power factor at the transmission side of the distribution transformer is 98 % when load is within 10 % of the forecasted system minimum or peak. Any interconnecting facility is expected to provide sufficient reactive power (leading or lagging) such that during these load periods the high side power factor does not exceed 98 %.

2) Generator specific power factor requirements.

   Self service generators serving load will be expected to provide sufficient facilities and controls to operate their combined generation and a load with a 95 % power factor or be subject to the power factor charges associated with the service rate. All other generation applicants are required to provide unity power factor, unless providing reactive supply and voltage control from generation source service.

In **South Africa**, units shall be designed to supply rated power output (MW) for power factors ranging between 0.85 lagging and 0.95 leading.

### *VII.2 Voltage control*

It is necessary to transmit electricity at high voltage to reduce the percentage of energy loss. For a given amount of power transmitted, a higher voltage reduces the current and resistance losses in the conductor. Long distance transmission is typically at voltages of 100 kV and higher. Transmission voltages up to 765 kV AC and up to +/-533 kV DC are currently used in long distance overhead transmission lines.

For voltage control in **Sweden and Denmark**, the preferred dynamic characteristics for steady state are defined in a measurable way as follows:

1) 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 - 105 %, and from 105 - 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 seconds in case of static exciter, or in case of brush less exciter: 0.2 - 0.5 seconds at a step upwards, 0.2 - 0.8 seconds at a step downwards.
   Overshoot is less than 15 % of the change.

2) Additional voltage control equipment such as 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.

3) For 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.

4) The HVDC service in the Nordel power system becomes relevant when low voltage activates emergency power on HVDC links out from the synchronous system. The service is applicable to exchanges.

For the **UK** CCGT plant voltage control, each generating unit is required to have a fast acting excitation control system to control terminal voltage with stability across its entire operating range. It should be noted that constant Mvar and/or power factor control, which may be supplied as standard modules within the excitation control system, are not acceptable to NGC because of their adverse impact upon transmission system voltage stability.

Regarding voltage response and control in **New Zealand**, each grid connected generator shall have an excitation and voltage control system with a voltage set point that is adjustable over the range of voltages for **New Zealand** mentioned above and will operate continuously in the voltage control mode when synchronised; and in order to meet the asset owner performance obligations, ensure that each of its generating units is equipped with a connection transformer with an appropriate range of taps on each transformer together with an on-load tap changer.

Where the output of more than one generating unit is controlled by a common control system, the generator must ensure that:

The common control system does not adversely affect the ability of the system operator to plan to comply, and to comply, with the principal performance obligations.

The combined output from the generating units performs as though it were from one generating unit.

Such control system does not degrade the individual performance of any one generating unit.

With a disturbed network the generating units in **Germany** must support the voltage. The support of the network voltage must be provided within 20 ms after fault identification by providing reactive power at the generator terminals with a 2 % factor of the rateed actual percentage of the voltage drop. Switching back from voltage control to operation is possible after 3 seconds.

### *VII.3 AVR (Automatic Voltage Regulation)*

A voltage regulator is an electrical regulator designed to automatically maintain a constant voltage level. With the exception of shunt regulators, all voltage regulators operate by comparing the actual output voltage to some internal fixed reference voltage. Any difference is amplified and used to control the regulation element. If the output voltage is too low, the regulation element is commanded to produce a higher voltage. If the output voltage is too high, the regulation element is commanded to produce a lower voltage. In this way, the output voltage is held roughly constant.

In **South Africa** a unit shall have a continuously acting automatic excitation control system (AVR) and shall comply with the requirements specified in IEC 60034. Load angle limiter and flux limiter as described in IEC60034-16-1. The excitation system shall have a minimum excitation ceiling limit of 1.6 p.u. rotor current, where 1 p.u. is the rotor current required to operate the unit at rated load and at rated power factor as defined in IEC 60034.

For **India** all generating units shall normally have their automatic voltage regulators (AVRs) in operation, with appropriate settings. In particular, if a generating unit of over 50 MW (10 MW in case of north-eastern region) size is required to be operated without its AVR in service, the RLDC shall be immediately intimated about the reason and duration, and its permission obtained. Power System Stabilizers (PSS) in AVRs of generating units (wherever provided), shall be properly tuned as per a plan prepared for the purpose by the CTU from time to time. CTU will be allowed to carry out tuning/checking of PSS wherever considered necessary.

A generating unit shall be provided with an automatic voltage regulator (AVR) protective and safety devices, as set out in connection agreements.

### *VII.4 Voltage stability*

Following major system faults, in **UK** voltage variations, the maximum over voltage values given may occur but the duration will not exceed 15 minutes unless exceptional circumstances prevail. See table 7.7

| Nominal Voltage (kV) | Normal range | 15 Minutes Over voltage |
|---|---|---|
| 400 | ±5 % | +10 % |
| 275 | ±10 % | +15 % |
| 132 | ±10 % | +20 % |

Table 7.7 Voltage variations for system faults in UK.

Under fault and circuit switching conditions the rated frequency component of voltage could fall transiently to zero on one or more phases or rise to 150 % of nominal phase to earth voltage.

Under planned outage conditions the maximum negative phase sequence component of the phase voltage on the transmission system should remain below 2 % unless exceptional circumstances prevail.

Voltage stability in the **German grid** forms part of the measures for maintenance of a secure supply, for which the responsible system operator bears responsibility.

The minimum requirements for the design of the transmission systems must be coordinated between the TSOs at their interfaces:

Insulation coordination.
Assurance of local reserves for provision of reactive power which are sufficient at all times.
The maximum and minimum voltage levels for continuous operation, duration and level of the short time violations of the maximum and minimum limits.
The type and volume of the reactive power interchange and limitation of the power factor cos **ϕ**.
Observance of all network criteria including voltage stability and reactive power management for relevant load and switching states shall be demonstrated in the course of network planning.

The following framework conditions must be observed in normal operation in the vicinity of the interconnecting lines:

1) Observance of the minimum and maximum permissible voltages.
2) Many TSOs employ U/Q optimization (i. e. voltage/reactive power). This requires coordination with regard to the specific interconnecting line nodes:

   Extension of U/Q optimization to the first mesh of each adjacent network with the objective of modifying the agreed voltage bands for the benefit of both parties where appropriate.
   Supply of measured values from joint sensors.
   Should a voltage limit be violated, the TSO responsible for the violation must ensure corrective intervention.

3) Agreements must be reached if necessary concerning reactive compensation for the falling/rising voltage in the region of the interconnecting line nodes in the peak/low-load case. Instructions for such actions must be followed immediately. This may involve:

   The operation of reactive compensation equipment (e.g. shunt reactors, capacitor banks, FACTS).
   Tapping position of transformers.
   Provision of reactive power from generating units and synchronous condensers, over/under excited.
   Line switching.
   Disconnection of contractually agreed loads (e.g. pump operation in pumped-storage power stations).

Most of the **USA** electricity system at 12.5 kV and below is voltage regulated. When the interconnection is with a portion of the electric company's delivery system that is regulated, then the applicant shall be capable of tolerating steady state voltage fluctuations $\pm$5 % of the nominal voltage level.

The electricity system is designed to avoid experiencing dynamic voltage dips below 0.70 p.u. due to external faults or other disturbance initiators. The applicant should allow sufficient dead bands in its voltage regulation equipment control to avoid reacting to dynamic voltage dips.

# VIII. Quality

As a result of the deregulation, quality has become a very important issue, for this reason supplier and costumer relationship has become more important due to the high competitive market with the energy supply companies.

## *VIII.1 Voltage quality*

Before, quality measurements were done when there was a complaint from the customer, now electricity suppliers permanently monitor the voltage quality in the network. In this chapter we will look at some of the most important events which are responsible for network disturbances.

For large voltage disturbances in **Sweden and Denmark**, 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.

For over voltages due to switching operations 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.

Over voltages on the overhead lines of the grid due to atmospheric phenomena (lightning) are largely limited by the dielectric strength of the lines and the over voltage 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.

For thermal power plant 100 MW, 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 (a rapid voltage variation that causes a voltage, which falls below 90 % of the pre-existing voltage, is regarded as a voltage dip). See table 2.1 of Chapter 2.

The aim is to keep the measured value for short term flicker ($P_{st}$) below 1.0 and the measured value for long-term flicker ($P_{lt}$) 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.

The voltage may rise up to 1.8 times the rated voltage, depending on the earthing method used in the grid.

Also the following must be taken into consideration due to consequences of nearby grid faults:

1) 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 seconds. Neither damage nor needs for immediate stoppage for study of the possible consequences are allowed.

2) Line side faults of clearing time up to 0.25 seconds. 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 seconds. A unit equipped with a large single shaft turbine generator may be disconnected from the grid at a shorter time limit, if it is obvious that it will be impossible to maintain stability anyway. In this case a solution must be agreed upon with the grid operator.

3) Deep voltage transient the units shall be designed so that they can withstand the following generator voltage variation resulting from faults in the grid, without disconnection from the grid:

    Step reduction to 25 % of the rated generator voltage lasting for 0.25 seconds.
    Followed by linear increase to 95 % in 0.5 seconds.
    Followed by constant generator voltage 95 %.

   Consequently, only a small power reduction can be accepted.

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.

All **UK** plant and apparatus connected to the NGC transmission system, and that part of the NGC transmission system at each connection site, should be capable of withstanding the following distortions of the voltage waveform in respect of harmonic content and phase unbalance:

1) Harmonic content. The electromagnetic compatibility levels for harmonic distortion on the NGC transmission system from all sources under both planned outage and fault outage conditions, (unless abnormal conditions prevail) shall comply with the levels shown in the tables of Appendix A (not on this document) which contains the planning criteria that NGC will apply to the connection of non-linear load to the NGC transmission system, which may result in harmonic emission limits being specified for these loads in the relevant bilateral agreement.[15]

2) Phase unbalance. Under planned outage conditions, the maximum phase (voltage) unbalance on the NGC transmission system should remain below 1 % unless abnormal conditions prevail. Under the planned outage conditions stated in (b) infrequent short duration peaks with a maximum value of 2 % are permitted for phase (voltage) unbalance.

For grid voltage variations in the **UK**, the voltage on the 400 kV part of the NGC transmission system at each connection site with a user will normally remain within 5 % of the nominal value unless abnormal conditions prevail. The minimum voltage is -10 % and the maximum voltage is +10 % unless abnormal conditions prevail, but voltages between +5 and +10 % will not last longer than 15 minutes unless abnormal conditions prevail. Voltages on the 275 kV and 132 kV parts of the NGC transmission system at each connection with a user will normally remain within the limits 10 % of the nominal value unless abnormal conditions prevail. At nominal system voltages below 132 kV the voltage of the NGC transmission system at each connection site

[15] Based on the Engineering Recommendation G5/4.

with a user will normally remain within the limits 6 % of the nominal value unless abnormal conditions prevail. Under fault conditions, voltage may collapse transiently to 0 at the point of fault until the fault is cleared.

The dynamic nature of the power system requires that the CCGT plant be able to maintain its active and reactive output as system voltage varies. In respect of active power capability should be maintained across the voltage ranges specified in under normal operating conditions and in respect of reactive power capability should be marked for a voltage range within 5 % of nominal. This latter criterion ensures that the generating unit step up transformer is sized accordingly.

### *VIII.2 Voltage collapse*

It is neither of interest nor possible to specify in at exactly 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.

For **Sweden and Denmark** 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.

With a view to controlling the voltage collapse in the **German grid**, it may occur within the stability's limit range at the generator terminals and on the generating unit's auxiliary supply, it is permitted to use a shorter fault clearing time (at least 100 ms) in agreement with the system operator.

### *VIII.3 Voltage dip*

For voltages above 110 kV in **Sweden** and **Denmark**, 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.

### *VIII.4 Voltage fluctuations / Flicker*

A sudden and noticeable change in rms voltage level is known as a voltage fluctuation, usually caused by changing system loads, a repetitive voltage fluctuation is known as a voltage flicker, this can cause irritation to people noticing the effects on equipment such as lights and televisions.

In the **USA**, the flicker limits are applicable to all interconnections made to the company's electric system. In the case where the applicant owns a dedicated line so that the electricity company's other costumers will be protected, a waiver may be permitted.

Applicants are not allowed to produce flicker to adjacent customers that exceeds figure 8.1, the applicant will be responsible and liable for corrections if the interconnecting facility is the cause of objectionable flicker levels.

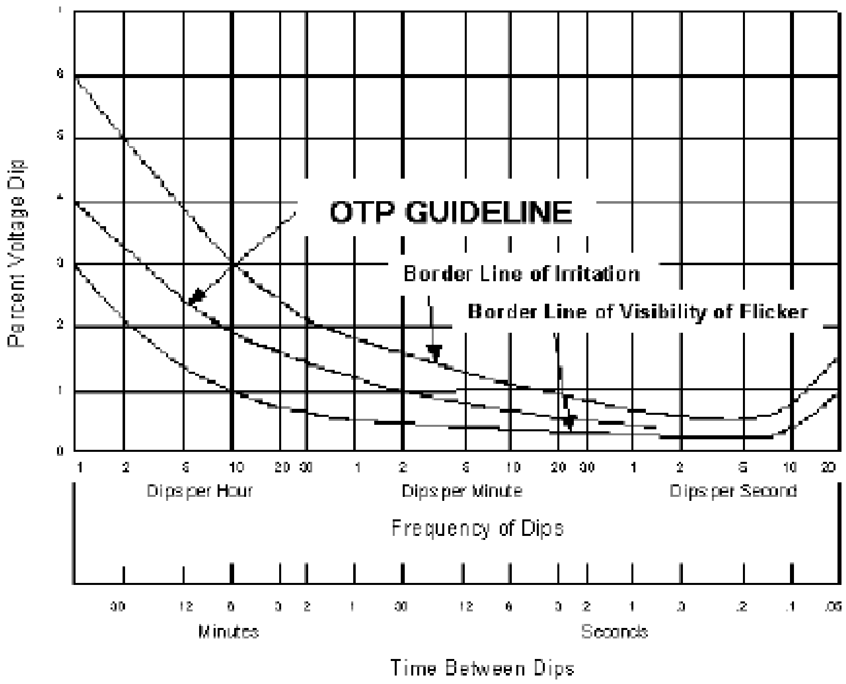



Figure 8.1 Voltage flicker guideline for the USA.

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** a limit value of 1 % is used.

In the **UK**, voltage fluctuations at a point of common coupling with a fluctuating load directly connected to the NGC transmission system shall not exceed:

1) 1 % of the voltage level for step changes which may occur repetitively. Any large voltage excursions other than step changes may be allowed up to a level of 3 % provided that this does not constitute a risk to the NGC transmission system or, in NGC's view, to the system of any user.

2) Flicker severity (short term) of 0.8 unit and a flicker severity (long term) of 0.6 unit.

### *VIII.5 Harmonics*

Harmonics can cause telecommunication interference, increase thermal heating in transformers, disable solid state equipment and create resonant over voltages. In order to protect the equipment from damage, harmonics must be managed and mitigated. In the **USA** the applicants interconnecting equipment shall not introduce excessive distortion to the company's electric system voltage and current waveforms per IEEE 519-1992.

The harmonic distortion is defined as the ratio of the root mean square (rms) value of the harmonic to the rms value of the fundamental voltage or current. The harmonic distortion measurement and voltage distortion limits shall be made at the point of interconnection between the applicants and the company's electric system and shall be within the limits specified in the tables 8.1 and 8.2. The electricity company advises the applicant to account for harmonics during the early planning and design stages.

| Bus Voltage At PCC | Individual Voltage Distortion IHD % | Total Voltage Distortion THD % |
|---|---|---|
| Below 69 kV | 3.0 | 5.0 |
| 69 kV to 115 kV | 1.5 | 2.5 |
| 115 kV and above | 1.0 | 1.5 |
| *Source: IEEE 519, Table 11.1* | | |

Table 8.1 Voltage distortion limits in the USA

| Maximum Harmonic Current Distribution in % of Fundamental Harmonic Order (Odd Harmonics) | | | | | | |
|---|---|---|---|---|---|---|
| I(sc)/I(l) | <11 | 11<h<17 | 17<h<23 | 23<h<35 | 35<h | THD |
| 20 | 4.0 | 2.0 | 1.5 | 0.6 | 0.3 | 5.0 |
| 20-50 | 7.0 | 3.5 | 2.5 | 1.0 | 0.5 | 8.0 |
| 50-100 | 10.0 | 4.5 | 4.0 | 1.5 | 0.7 | 12.0 |
| 100-1000 | 12.0 | 5.5 | 5.0 | 2.0 | 1.0 | 15.0 |
| 1000 | 15.0 | 7.0 | 6.0 | 2.5 | 1.4 | 20.0 |

Where:
I(sc) = Maximum short circuit current at PCC
I(l) = Maximum load current (fundamental frequency) at PCC
PCC = Point of Common Coupling between Applicant and utility

Generation equipment is subject to the lowest I(sc)/I(l) values
Even harmonics are limited to 25% of odd harmonic limits given above

*Source: IEEE 519, Table 10.3*

Table 8.2 Distortion limits for non-linear loads at the point of common coupling (PCC) from 120 to 69,000 Volts in the USA.

Lower order harmonics, particularly the third and ninth harmonics, will often be of more concern to the owner of the generator. These are often related to generator grounding, and to the type of transformer connections that may be involved. It is to the applicant’s advantage to work these problems out early enough so that applicant and the electricity company’s equipment can be acquired to achieve proper control.

All plant and apparatus connected to the **UK** transmission system shall be capable of withstanding the levels of harmonic distortion liable to be present on the transmission system.

For **Sweden** see table 8.3 for the planning levels for harmonic voltages.

| Odd<br>Multiples other than 3 | | Odd<br>Multiples of 3 | | Even | |
|---|---|---|---|---|---|
| n | Sweden | n | Sweden | n | Sweden |
| 5 | 2.5 % | 3 | 2.5 % | 2 | 1.0 % |
| 7 | 2.5 % | 9 | 1.5 % | 4 | 0.5 % |
| 11 | 1.5 % | 15 | 0.7 % | 6 | 0.5 % |
| 13 | 1.5 % | 21 | 0.7 % | 8 | 0.2 % |
| 17 | 1 % | >21 | 0.7 % | 10 | 0.2 % |
| 19 | 1 % | | | 12 | 0.2 % |
| 23 | 0.7 % | | | >12 | 0.2 % |
| 25 | 0.7 % | n = Harmonic number | | | |
| > 25 | 0.2 + 0.25* (25/n) | | | | |
| Total Harmonic Distortion (THD) for the voltage > 4 % in Sweden | | | | | |

Table 8.3 Planning levels for harmonic voltages as a percentage of the nominal voltage in Sweden.

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, 0.5 % in Sweden. Voltages and intermediate harmonics are generated by arc furnaces, welding equipment and fast frequency converters.

# IX. Protection requirements

The function of transmission protection systems is to protect the transmission system when subjected to faults. System conditions, particularly during emergency operations, may make it necessary for transformers to become overloaded for short periods of time. In those moments, it is important that protective relays do not prematurely trip the transmission elements out-of-service.

## *IX.1 System protection requirements*

Mentioned below are some of the protection design standards to be implemented to avoid system collapse at different voltages levels.

In **India,** protection systems are required to be provided by all Constituents/ISGS/CTU/ SEB/STU connected to the ISTS. These are required to isolate the faulty equipments and protect the other components against all types of faults, internal/ external to them, within the specified fault clearance time with reliability, selectivity and sensitivity.

All agencies connected to the ISTS shall provide protection systems as specified in the connection agreement. Relay setting coordination shall be done at regional level by REB.

### IX.1.1220 kV and above

For the protection design standards, in **South Africa,** an additional earth fault function shall be incorporated in the main protection relays or installed separately to alleviate possible deficiencies of distance relays in the detection of high resistance faults.

The protection relays shall provide reliable protection against all possible short circuits and shall provide remote and/or local backup for busbar faults that have not been cleared and shall not be set to provide overload tripping.

Where specifically required, the feeder protection may be set, if possible, to provide remote backup for other faults as agreed upon with other participants.

Automatic Reclosing (ARC) facilities shall provide on all feeders, the system operator shall decide, in consultation with customers, on ARC selection:

1) Single phase ARC: The dead time of single phase ARC shall be selected to one second.

2) Three phase ARC: The fast ARC, shall be used only in exceptional circumstances to avoid stress to the rotating machines at the power stations and at the customer’s plant. The slow ARC is set to three seconds at the DLC end of the line, at the synchronizing end of the line the ARC dead time is usually set to four seconds. The close command will be issued only after synch-check is completed. This may take up to two seconds if synchronizing relays are not equipped with direct slip frequency measurement.

On the line between two power stations the dead time at the DLC end should be extended to 25 seconds to allow units rotor oscillations to stabilize. The dead time on the synchronizing end is then accordingly extended to 30 seconds.

### IX.1.2132 kV and below

For the protection design standards in **South Africa**, the TNSP shall ensure that these feeders shall be protected by a single protection system. Backup shall be provided by definite time and inverse definitive minimum time (IDMT) over current and earth fault relays. The customer shall determine ARC requirements.

For the protection of lower voltage systems in the **UK**, the transmission system will be equipped with back up protection which will be expected to operate only in the event of a failure to operate of the network operators’ and directly connected customers’ main protection, or failure to trip of the associated circuit breaker.

In order to minimize the impact on the transmission system of faults on circuits owned by network operators and directly connected customers, protection of any lower voltage system supplied from the transmission system by direct transformation must meet the minimum requirements given below:

1) Fault clearance times.

The maximum fault clearance time of faults on the user's system shall not exceed 250 ms. The probability that this time will be exceeded, for any given fault, shall be less than 2 %.

2) Fault disconnection facilities.

In these circumstances, for faults on the user's system, the user’s protection should also trip higher voltage company circuit breakers and suitable facilities will be provided by the company. Tripping facilities shall be in accordance with the requirements of the connection agreement and/or use of system agreement.

3) Automatic switching equipment.

Where automatic reclosure of company circuit breakers is required following faults on the user's system, automatic switching equipment shall be provided in accordance with the requirements of the connection agreement and/or use of system agreement

Each generator in **New Zealand** with a point of connection to the grid will at all times ensure its assets, load shedding obligations to support voltage are as followed:

Grid owners to shed load.

Where it is not possible for distributors to comply with distributors to shed load, the grid owner will, if possible, establish load shedding in block sizes and at voltage levels (and, where automatic systems are established, with relay settings) set out in the technical codes or otherwise as the system operator reasonably requires.

Distributors to shed load.

In order to prevent the collapse of the network voltage, distributors will ensure that, where possible, they have established load shedding in block sizes and at voltage levels (and, where automatic systems are established, with relay settings) in accordance with the technical codes or otherwise as the system operator reasonably requires.

Concerning all the countries, the combination of operating conditions, faults or other disturbances may cause the loss of synchronism between areas within the power system or between interconnected systems. If loss of synchronism does occur, the asynchronous areas must be separated before equipment is damaged or before a wide spread outage can occur.

System separation because of instability should not be a random procedure, the system should be separated at such points as to maintain a balance between load and generation in each separated area. Separation should be performed quickly and automatically in order to minimize the disturbance to the system and to maintain maximum service continuity.

Over the years, a number of protective relays and schemes have been developed to detect a loss of synchronism and to perform the necessary functions to preserve the system.[16]

### *IX.1.3Out-of-step tripping*

In **India**, any tripping, whether manual or automatic, of any of the elements of regional grid shall be precisely intimated by the concerned state LDC/CTU/ISGS to RLDC as soon as possible, say within 10 minutes of the event. The reason (to the extent determined) and the likely time of restoration shall also be intimated. All reasonable attempts shall be made for the elements' restoration as soon as possible.

The purpose of the out-of-step tripping protection in **South Africa** is to separate the IPS in a situation where a loss of synchronous operation takes place between a unit or units and the main power system.

[16] http://pm.geindustrial.com/faq/Documents/Alps/GER-3180.pdf

### IX.1.4Multiple Unit Tripping (MUT)

In **South Africa** there are 2 categories of MUT.

Category 1: Unplanned disconnection or tripping of more than one unit instantaneously or within a one hour window, where the total maximum continuous rating (MCR) of those units exceeds the largest credible multiple contingencies.

Category 2**:** Unplanned disconnection or tripping more than one unit instantaneously or within ten minutes, where the total MCR of those units exceeds the largest single contingency.

The power station shall be designed such that no MUT category 1 trip risk can occur and a MUT category 2 trip will not occur more than once in ten years.

### IX.1.5Under voltage load shedding

Under voltage load shedding protection schemes in **South Africa** are used to prevent loss of steady state stability under conditions of large local shortages of reactive power (*voltage collapse*). Automatic load shedding of suitable loads is carried out to arrest the slide.

### IX.1.6Sub-synchronous Resonance protection (SSR)

The SSR condition in **South Africa** may arise on the IPS where a unit is connected to the IPS through long series compensated transmission lines. The potential for unstable interaction is related to system topology and is greater where higher degrees of compensation and if larger thermal units are employed. The SSR condition is addressed through either protection or mitigation

### IX.1.7Overvoltage protection

In the **USA**, temporary over voltages can last from seconds to minutes, and are not characterized as surges. These over voltages are present during islanding, faults, loss of load, or long line situations. All new and existing equipment must be capable of withstanding these duties.

a) Islanding.

   A “local island” condition can expose equipment to higher than normal voltages. Special relays to detect this condition and isolate the local generation from the electricity company’s facilities may be required.

b) Neutral shifts.

   When generation or a source of “back feed” is connected to the low voltage side of a delta grounded wye customer service transformer, remote end breaker operations initiated by the detection of faults on the high voltage side can cause over voltages that can affect personnel safety and damage equipment. This type of over voltage is commonly described as a neutral shift and can increase the voltage on the un-faulted phases to as high as 1.73 p.u. At this voltage, the equipment insulation withstand duration can be very short. Several alternatives remedies are possible:

Provide an effectively grounded system on the high voltage side of the transformer that is independent of the company's electricity system connections.
Size the high voltage side equipment to withstand the amplitude and duration of the neutral shift.
Rapidly separate the back feed source from the step up transformer by tripping a breaker using either remote relay detection with pilot scheme (transfer trip) or local relay detection of over voltage condition.

Methods available to obtain an effective ground on the high voltage side of the transformer include:

A transformer with the transmission voltage (electricity company) side connected in a grounded wye configuration and low voltage (connection point) side in closed delta.
A three-winding transformer with a closed delta tertiary winding. Both the transmission and distribution side windings are connected in grounded wye.
Installation of a grounding transformer on the transmission voltage (electricity company) side.

In **South Africa**, primary protection against high transient over voltages of magnitudes above 140 % (e.g. induced by lightning) shall be provided by means of surge arrestors.

Overvoltage protection on shunt capacitors is set to disconnect the capacitor at 110 % voltage level with a typical delay of 200 ms to avoid unnecessary operations during switching transients.

Overvoltage protection on the feeders is set to trip the local breaker at a voltage level of 120 % with a delay of one to two seconds.

### *IX.1.8Generating units*

For the **UK**, the generator must provide protection to detect loss of generator excitation and initiate a trip of the associated generating unit.

Where, in the company's reasonable opinion, system requirements dictate, the company will specify in the connection agreement and/or use of system agreement a requirement for generators to fit pole slipping protection on generating units.

Generating units shall be capable of withstanding, without tripping, a negative phase sequence loading appropriate to their rated full load in accordance with the provisions of IEC Standard 34/1.

For an UK CCGT plant, generating unit protection should fulfil the following generic requirements to reduce to a practical minimum the impact of faults, and to establish, as far as is practicable, appropriate discrimination between the transmission system and generating unit protection systems:

Main fault clearance, time for faults on generating equipment directly connected to the transmission system generally not faster than 80 ms at 400 kV, 100 ms at 275 kV, 120 ms at 132 kV and below.
Back up fault clearance, time for faults on HV generator connections 300 ms if one main protection, 800 ms if two main protection.

Breaker fail, on failure to interrupt fault current breaker fail should enable fault current interruption in the next 200 ms.
Busbar, integration into busbar protection as specified in the supplemental agreement.
Loss of excitation.
Pole slipping, where identified as necessary is specified in the supplemental agreement.

In **South Africa** the generating units shall be equipped with well-maintained protection functions to rapidly disconnect appropriate plant sections. Tripping and fault clearing time including breaker operating time, shall not exceed the following:

120 ms plus an additional 30 ms for DC offset decay, or
100 ms plus an additional 40 ms for DC offset decay.

All the new capacitor banks shall be equipped with sequence switching relays to limit inrush current during capacitor bank energization.

The following protection functions shall be provided for all types of protection schemes:

Unbalanced protection with alarm and trip stages.
Over current protection with instantaneous and definite time elements.
Earth fault protection with instantaneous and definite time-sensitive function.
Overload protection with IDMT characteristic.
Over voltage with definite time.
Circuit breaker close inhibit for 300 seconds after de-energization.

The protection requirements for **India's** generating units are as follows:

1) Except under an emergency, or to prevent an imminent damage to a costly equipment, no constituent shall suddenly reduce his generating unit output by more than one 100 MW (20 MW in case of North-Eastern region) without prior intimation to and consent of the RLDC, particularly when frequency is falling or is below 49.0 Hz. Similarly, no constituent shall cause a sudden increase in its load by more than one 100 MW (20 MW in case of north eastern region) without prior intimation to and consent of the RLDC.

2) A Generating Unit shall be capable of continuously supplying its normal rated active/reactive output within the system frequency and voltage variation range.

The protection requirements for **New Zealand's** generating units are:

1) Each of its generating units and its associated control systems supports the system operator to plan to comply, and to comply, with the principal performance obligations; and is able to synchronise at a stable frequency within the frequency range stated in the asset capability statement for that asset.
2) The rate of change in the output of any of its generating units does not adversely affect the system operator's ability to plan to comply, and to comply, with the principal performance obligations. The rate of change must be adjustable to allow for changes in grid conditions;

### *IX.1.9Network protection*

Provision of protections and relay settings in **India** shall be coordinated periodically throughout the regional grid, as per a plan to be separately finalized by the protection committee of the REB.

Reliable interconnected operation shall be assured with regard to the network equipment of the transmission system by installation by each TSO of protective equipment for his part of the **German network** which conforms to:

The topology and operating conditions of his transmission system.
The interface conditions of other transmission systems. The protective equipment must be capable of handling all voltages, currents and frequencies arising in operation.
Distance protection of the lines.
Differential protection and *Buchholz protection* for transformers.
Distance protection in the relevant switchgear panels in the remote stations and/or special busbar protection for protection of the busbars.

The conditions at the interfaces between the installations of adjacent TSOs shall be coordinated bilaterally such that no risk is presented to the adjacent facilities.

Protective equipment on the German network and in the power station must be agreed between the TSO's and the power station operators. Consideration must be given to the following points:

External short circuits.
Load unbalance.
Stator and rotor overload.
Under excitation.
Network oscillations.
Over frequency, under frequency.
Asynchronous operation.
Torsional strain.
Drive failure (operation as motor).
Protective and breaker failures.
Back up protection.

High voltage **German networks** operate with arc-suppression-coil-earthing:

For transformers 100 % first zone time protection (fault clearance times 150 ms).
For lines an overlapping of the distance protection with three phase automatic reclosure with intervals from 0.4 to 0.8 seconds and subsequent triggering according to the time grading schedule if applicable.

ENE will specify the permissible back up times at the network connection node.

The function of the remote back up protection of ENE for the systems of the connectee can not always be guaranteed, and especially not for faults on the low voltage side of the transformers (connectee side).

Considerable longer fault clearing times than 50 ms can also occur in the extra high voltage network should a protection device or a circuit breaker fail.

These requirements for network protection permit the disconnection of equipment subject to a disturbance and prevent the disturbance from spreading.

Reliable, low disturbance operation of the customer facility on the transmission system requires each connection user to install protective equipment for his part of the network which is appropriate for:

The topology and operating conditions of his network.
The conditions at the interface to the transmission system.

The protective equipment must be capable of handling all voltages, currents and frequencies arising in operation.

Regarding the protective relay requirements, all asset owners and grid owners in **New Zealand** must co-operate with the system operator to ensure that protection systems on both sides of a grid interface, which will include main and back up protection systems, are co-ordinated so that a faulted asset is disconnected by the main protection system first and the other assets are not prematurely disconnected.

For reliability and redundancy, each asset owner must ensure that sufficient circuit breakers are provided for its assets so that each of its assets are able to be disconnected totally from the grid whenever a fault occurs within the asset.

Each asset owner will ensure that it provides protection systems for its assets that are connected to, or form part of, the grid.

Such protection systems will support the system operator in planning to comply, and complying, with the principal performance obligations and must be designed, commissioned and maintained, and settings must be applied, to achieve the following performance in a reliable manner:

Disconnect any faulted asset in minimum practical time (taking into account selectivity margins and industry best design practice) and minimum disruption to the operation of the grid or other assets.

Be selective when operating, so that the minimum amount of assets will be disconnected.

As far as reasonably practicable, preserve power system stability.

Main protection systems on both sides of the grid interface at 220 kV are designed to follow industry best practice, such that there are either duplicate protections or two different main protections which have a similar probability of detection. Circuit breaker duplication is not required. A circuit breaker failure protection system shall be provided for each 220 kV circuit breaker; and protection system design for a connection of assets to the grid at lower voltages must be similar to existing design practice in adjacent connections of assets to ensure co-ordination of protection systems.

In the **UK**, the safety precautions on high voltage apparatus is the responsibility of the implementing safety co-ordinator to ensure that adequate safety precautions are established and maintained, on his and/or another system connected to his system.

The implementing safety co-ordinator shall then establish the agreed earthing, and then he shall confirm to the requesting safety co-ordinator that the agreed earthing has been established, and identify the requesting safety co-ordinator’s HV apparatus up to the connection point, for which the earthing has been provided

In **South Africa**, the standard busbar arrangements and security criteria shall be based on providing one busbar zone for every main transformer/line normally supplying that busbar.

A circuit breaker bypass facility with single busbar selection shall be used at 275 kV on single line radial feeds to provide continuity of supply when the line breakers are being maintained.

A circuit breaker bypass facility with double busbar selection shall be used on new 400 kV and 765 kV lines and 275 kV lines.

Earthing and surge protection is required for:

The safety of personnel and the public.
The correct operation of all protection systems.
Agreed design and performance levels.

Earthing isolators shall be provided at new substations where the fault level is designed for 20 kA and above.

The standard schemes for transformer protection comprise a number of systems, each designed to provide the requisite degree of protection for the following fault conditions:

Faults within the tank.
Faults on transformer connections.
Overheating.
Faults external to the transformer.

Transmission busbars shall be protected by current differential protection (buszone) set to be as sensitive as possible for the “in zone faults” and to maintain stability for any faults outside the protected zone, even with fully saturated CT's.
At power stations, overlapped bus zones shall be retained to ensure the fastest possible clearance of busbar faults.

#### IX.1.9.1 **Special conditions**

The (n – 1) criterion in **Sweden and Denmark** 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.

### *IX.1.10Fault Interrupting Devices*

The most common devices used by the **USA** are:

1) Circuit breaker.

   The electricity company will have the operational authority to operate all intertie circuit breakers at all installations where the applicant’s generation has been classified as greater than 5 MW and for all substation or tie line interconnection.

   A three phase circuit breaker at the point of interconnection automatically separates the applicant’s facility from the company’s electricity system upon detection of a circuit fault. The interconnection breaker must have sufficient capacity to interrupt maximum available fault current at its location and be equipped with accessories to:

   Trip the breaker with an external trip signal supplied through a battery (shunt trip).

Telemeter the breaker status when it is required.
Lockout if operated by protective relays required for interconnection.

2) Circuit switches.

A circuit switcher is a three phase fault interrupter with limited fault interrupting capability. These devices have typically been used at voltages of 115 kV and below and may substitute for circuit breakers when the fault duty is within the interrupting rating of the circuit switcher. Since circuit switchers do not have integral current transformers, they must be installed within 10 meters of the associated current transformers to minimize the length of the unprotected line/bus section.

3) Fuses.

Fuses are single phase, direct-acting sacrificial links that melt to interrupt fault current and protect the equipment. Blown fuses need to be replaced manually after each fault before the facility can return to service. Overhead primary fuses shall be replaced by trained, qualified personnel.

In limited cases, fuses may be used as a primary protective device (e.g. rural, 60 kV, 70 kV, and 115 kV lines, where the applicants substation is 12 MW or less).

For generator interconnections, fuses cannot be operated by the protective relays and therefore cannot be used as the primary protection for three phase generation facilities. Fuses may be used for high side transformer protection for generation less than 5 MW.

Single phase devices fuses/oil circuit reclosers.

It may be necessary to replace single phase devices (line fuses, single phase automatic circuit reclosers) installed between the electricity company's source substation and the applicants location with three phase devices. This is to minimize the possibility of single phasing an applicant's three phase generator.

In the **USA** as a rule, neither party should depend on the other for protection of its own equipment. It is the applicant's responsibility to protect its own system and equipment.

A manual disconnector (or breaker) device should be installed to isolate the company's electricity system from the applicant's facility. This device must have load break capability or means must be provided to trip off generation or load before operating the disconnector. This disconnector shall open the entire pole except the neutral and shall provide a visible air gap to establish required clearances for maintenance and repair work of the company's electricity system.

The disconnector must be accessible at all times to electric company's personnel. Disconnectors should allow for padlocking in the open position with standard electric company's padlock. The applicant's shall not remove any padlocks or the electric company's safety tags. The disconnector should be located outside of the building if possible. If not possible, applicant's must provide access to disconnector at all times (24 hour day phone number, guard desk, etc.)The disconnecting equipment must be clearly labeled.

Protective relays are required to promptly sense abnormal operating of fault conditions and initiate the isolation of the faulted area. Protective relays can generally be categorized into two groups: industrial grade and utility grade. Utility grades have a higher degree of reliability and accuracy and are required in most cases. The use of the electricity company's approved industrial grade relays may be permitted on generation installations rated less than 100 kW. Protective relay settings on interconnect breakpoints must be approved by the electricity company.

The electricity company requires line protective equipment to either:

1) Automatically clear a fault and restore power.

2) Rapidly isolate only the faulted section so that the minimum number of customers is affected by any outage.

Tables 3 and 4 of Appendix A provide protective device recommendations necessary to protect the electricity company's equipment and its customer's equipment against electrical faults (short circuits), degraded voltage or frequency operation, unwanted power flow and inadvertence out of phase closing of breakers/switches, also the minimum protection that the electricity company typically requires. Higher voltage interconnections require additional protection due to the greater potential for adverse impact to system stability and the greater number of customers who would be affected.

The failure to trip during fault or abnormal system conditions due to relay or breaker hardware problems or from incorrect relay settings, improper control wiring, etc. is always a possibility. The protection system must be designed with enough redundancy that failure of any one component still allows the facility to be isolated from the electricity company's power system under a fault condition. If the facility breaker does not trip, the incoming breaker should trip after a predetermined time delay. Similarly, if the incoming breaker fails to trip, the facility's breaker should trip. Where there is no incoming breaker, the electricity company's tie breaker may be tripped.

Line protection relays must coordinate with the protective relays at the electricity company's breakers for the line on which the applicant's facility is connected. The typical protective zone is a two-terminal line section with a breaker on each end. In the simplest case of a load on a radial line, current can flow in one direction only, so protective relays need to be coordinated in one direction and do not need directional elements. However, on the typical transmission system, where current may flow in either direction depending on system condition, relays must be directional. In addition, the complexity and the required number of protective devices increase dramatically with increases in the number of terminals in each protective zone. With two terminals in a protective zone, there are two paths of current flow. With six terminals there are six paths of current flow, and so on.

The breaker's relays must be set to have overlapping zones of protection in case a breaker within any given zone fails to clear. The line protection scheme must be able to distinguish between generation, inrush and fault currents.

For response of generating units in **Germany** with high symmetrical short circuit current component, near to generator three phase short circuits with a fault clearing time up to 150 ms throughout the operating range of the generating unit must not result in instability or isolation from the network in the short circuit power available on the network side of the interface "network generating unit" is higher than 6 times the rated active power of the generating unit after fault clearing.

For response of generating units in **Germany** with low symmetrical short circuit current component, near to generator three phase short circuits the active power output must resume immediately following fault clearing and be increased with a gradient of at least 20 % of the rated power per second.

The settings for the electrical protection devices must be agreed between ENE and the operator of a generating unit connects to the **German grid**. ENE will install protection devices for the equipment of ENE at the network connection node.

### *IX.1.11Insulation Coordination*

Voltage stresses in the **USA**, such as lightning or switching surges, and temporary over voltages may affect equipment function. Remedies depend on the equipment capability and the type and magnitude of the stress. In general, stations with equipment operated at 115 kV and above, as well as all transformers and reactors, shall be protected against lightning and switching surges. Typically, this includes station shielding against direct lightning strokes, surge arresters an all wound devices, and shielding with rod gaps (or arresters) on the incoming lines. The following requirements may be necessary to meet the intent of the electricity company's reliability criteria.

1) Surge protection.

   The interconnection shall have the capability to withstand voltage and currents surges in accordance with the environments defined in IEEE/ANSI C62.41 and IEEEC37.90.1.

   The electricity company recommends the applicant to install surge arresters for protection of transformers and other vulnerable equipment. Arresters shall be mounted in such a manner as to protect any of the electricity company's facilities from surges voltages.

2) Lightning Surges.

   If the requester proposes to tap a shield transmission line, the tap line to the substation must also be shielded, for an unshielded transmission line; the tap line does not typically require shielding beyond that needed for substation entrance. However, special circumstances such as the length of the tap line may affect shielding requirements.

   Lines at voltages of 69 kV and higher that terminate at the electricity company's substation must meet additional shielding and/or surge protection requirements. Incoming lines must be shielded for 0.8 km at 69 - 150 kV and 1.6 km at 230 kV and higher. Rod gaps must also be installed at the station entrance.

### *IX.1.12Restoration of supply*

No applicants in the **USA**, independent of interconnection type or generator size, shall energize a de-energized electricity company's circuit. The necessary control devises shall be installed by the applicant on the equipment to prevent the energization of a de-energized electricity company's circuit by the applicant's interconnected facility. Connection may be accomplished only via synchronization with the company's electricity system. All interconnecting circuit breakers/devices and all breaker/devices that tie another source to the electricity company will require synchro-check relaying. Authorization to energize a circuit may only be provided by the control area operator.

After the transition into islanding mode the generating units in **Germany** can be loaded with only auxiliary load for at least 3 hours.

Any generating unit a rated power of  100 MW must be capable of island operation under the following conditions:

The generating unit must be able to control the frequency provided that the resulting power deficit is not greater than the primary control reserve available in the island. With excess power it must be possible to reduce the load of the generating unit to minimum load.
It must be possible to maintain such type of island operation for several hours.
In island operating mode the generating unit must be able to regulate rapid load increases in amounts of up to 10 % of the rated load (however a maximum of 50 MW). The intervals between two successive load additions should be at least 5 minutes.

## *IX.2 Fault clearance times*

For the **UK** protection fault clearance times, users shall comply with the following requirements for fault clearance times (from fault inception to circuit breaker arc extinction) by main protection not exceeding:

400 kV network - 80 ms.
275 kV network - 100 ms.
132 kV network - 140 ms.

The probability that these times will be exceeded for any given fault must be less than 2 %.

Back up protection shall be provided with a target maximum fault clearance time of 300 ms to cover for the failure of the main protection.

In case of the failure to trip of a user's circuit breaker provided to interrupt fault current interchange with the transmission system, circuit breaker fail protection shall be provided to trip all necessary electrically adjacent circuit breakers within 300 ms.

The design reliability for protection shall be equal to or greater than 99 %.

The fault clearance time in **India**, for a three phase fault (close to the busbars) on agencies equipment directly connected to ISTS and for a three phase fault (close to the busbars) on ISTS connected to agencies equipment, shall not be more than:

100 ms for 800 kV and 400 kV.
160 ms for 220 kV and 132 kV.

Back up protection shall be provided for required isolation/protection in the event of failure of the primary protection systems provided to meet the above fault clearance time requirements. If a Generating Unit is connected to the ISTS directly, it shall withstand, until clearing of the fault by backup protection on the ISTS side.

# X. Contingency planning

The development of the transmission system may occur for a number of reasons, including but not limited to:

Changes to customer requirements or networks.
The introduction of a new transmission substation or point of connection or the modification of an existing connection between a customer and the transmission system.
The cumulative effect of a number of developments as referred to above.
The need to reconfigure, decommission or optimize parts of the existing network.

## *X.1 Planning and development*

In **South Africa**, the transmission system shall be developed in accordance with the prevailing NER regulatory framework, as being implemented from time to time.

For evaluation of the (n - 1) security within a network area, the (n - 1) criterion shall be applied for relevant time ranges with the generation schedule expected for the area from the instantaneous perspective (including injections from installations for HVDC transmission from plants using renewable energies).

Planning the code for the Nordic transmission system **(Sweden and Denmark)**, rules shall be used for the joint, synchronized Nordic transmission grid. This concerns principally the main grid, mainly 220 - 420 kV. Deterministic criteria are used in the planning of the grid. Special protection schemes are required to have a reliability that is on a level with primary protection.

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

1) Stable operation, local consequences: Only local consequences are acceptable.
2) Controlled operation, regional consequences: The consequences shall be limited and further controlled operation shall be maintained for most of the system.
3) Instability and breakdown instability is acceptable. Grid selection and extensive breakdowns can take place in the Nordic system.

### *X.1.1 Transmission system development plan*

The NTC in **South Africa** shall annually produce a Transmission System (TS) demand forecast for the next ten years by end August of each year, also the NTC shall annually publish a five year ahead TS development plan by end April.

In **Sweden and Denmark** Nordel planning codes have different specifications for the transmission capacity, one for direct current and other for alternating current.

The nominal transmission capacity for the direct current 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. This is measured on the AC side of the rectifier. For alternating current the transmission capacity the trading capacity is agreed between the TSO's and is lower, typically by 5 - 10 %.
The transmission capacity is determined on the basis that the grid must withstand the dimensioning fault (n - 1)

Congestion in the **German grid** exists if the operational (n - 1) criterion cannot be satisfied as a result of the load flow on the network under consideration.

### *X.1.2 Technical limits and targets for long term*

The NTC shall determine thermal ratings in **South Africa** for standard transmission lines and transformers ratings and they shall be determined and updated from time to time using IEC specifications.

The maximum steady state current should not exceed the rated current of the series capacitor. IEC 143 standards call for cyclic overload capabilities as follows:

8 hours in a 12 hour period: 1.1 times rated current.
30 minutes in a 6 hour period: 1.35 times rated current.
10 minutes in a 2 hour period: 1.5 times rated current.

The TNSP may require an occasional over current rating of: two hours once per year: 1.3 times rated current.

Reactive compensation, whether new or modified, may cause harmonic resonance problems. Any TNSP wishing to install or modify such equipment shall at its expense arrange for harmonic resonance studies to be conducted.

Normal and fault current ratings for standard switchgear are determined by the equipment manufacturer. These ratings, and the following limits specified for circuit breakers, shall not be exceeded:

Single phase breaking current: 1.15 times three phase fault current.
Peak making current: 2.55 times three phase rms fault current.

For secondary arc current during single phase reclosing, the secondary arc current shall not exceed:

20 amps rms with recovery voltage of 0.4 pu
40 amps rms with recovery voltage of 0.25 pu.

A system cannot be made 100 % reliable for long term planning purposes.

### *X.1.3 Network development*

Each generating unit 100 MW must be capable of frequency control on condition that the existing power deficit does not exceed the primary control reserve available in the isolated **German network.**

In the case of isolated (network) operation, the generating unit must be capable of compensating for impulsive load connections of up to 10 % of the nominal capacity (but not more than 50 MW). Intervals between two successive load connections should be at least 5 minutes.

## ***X.2 Recovery procedures***

During a total shutdown or partial shutdown and during the subsequent recovery, the grid code standards may not apply and the total system may be operated outside normal voltage and frequency standards. In a total shutdown and in a partial shutdown, it may be necessary to issue emergency instructions and it may be necessary to depart from normal balancing mechanism operation, in this section some of the recovery mechanisims will be analized.

In the **UK** there is an implementation of recovery procedures following a total shutdown or partial shutdown. Total shutdown is the situation existing when all generation has ceased and there is no electricity supply from external interconnections. Therefore, the total system has shutdown with the result that it is not possible for the total system to begin to function again without NGC's directions relating to a black start. A partial shutdown is the same as a total shutdown except that all generation has ceased in a separate part of the total system and there is no electricity supply from external interconnections or other parts of the total system to that part of the total system.

Switchgear and the networks shall be designed so that faults will be automatically isolated from the **German network** without delay if possible, and propagation of the fault is avoided.

In the case of the 0 voltage condition due to a fault, changes to the switching status of the network connection should only be made after consultation of the responsible ENE system control centre.

### *X.2.1 Black Start*

In the event of a total shutdown or partial shutdown, the company will declare to users (or in the case of a partial shutdown, to users which in the company's opinion need to be informed) that a total shutdown or, as the case may be, a partial shutdown, exists and that the company intends to implement the black start procedure.

Restoring power after a wide-area power outage can be difficult, as power stations need to be brought back on-line. Normally, this is done with the help of power from the rest of the grid. In the absence of grid power, a so-called **black start** needs to be performed to restore the power grid into operation.

To provide a black start, some power stations are typically equipped with small diesel generators which can be used to start larger generators, which in turn can be used to start the main power station generators. It is uneconomic to provide such a large standby capacity at each station, so black-start power must be provided over the electrical transmission network from other stations.

This service is of a local nature, for **Denmark** the TSO in charged of the black starts is Elkraft System, and for this type of service use diesel generator and/or gas turbines. And for **Sweden** the company in charged is Svenska Kraftnät and usually use some selected hydropower plants.

Black start capability must be available from the power station in **Germany** operator if required and requested by the system operator for network reasons.

It is an essential requirement that the **UK** transmission system must incorporate a black start capability. Recovery procedures are the same for total and partial shutdown. Certain generating units are registered, pursuant to the connection conditions, as having an ability to start up from shutdown without an external electrical power supply, such generating units being referred to in this operating code as black start generators.

In **South Africa**, the units that do not have unit black start capabilities shall be capable of unit islanding and restart after power station black out, with a supply at least of 90 % voltage and unbalance between phase voltages of not more than 3 % negative sequence.

### *X.2.2 Re-synchronization of islands*

In the **UK,** the re-synchronisation of parts of the total system which have become out of synchronism with each other but where there is no total shutdown or partial shutdown, where parts of the total system are out of synchronisation with each other, but there is not total or partial shutdown of the total system, the company will instruct users to regulate generation or demand, as the case may be, to enable the de-synchronised power islands to be re-synchronised to achieve at the earliest practical time a return to the objectives of frequency control. Users shall at all times abide by the company's instructions to re-synchronise.

### *X.2.3 Joint system incident procedure*

The establishment in the **UK** of a communication route and arrangements between senior management representatives of NGC and users involved in, or who may be involved in, an actual or potential serious or widespread disruption to the total system or a part of the total system, which requires, or may require, urgent managerial response, day or night.

A "joint system incident" is:

> An event, wherever occurring (other than on an embedded small power station or embedded medium power station), which, in the opinion of NGC or a user, has or may have a serious and/or widespread effect.
> In the case of an event on a user(s) system(s) (other than on an embedded small power station or embedded medium power station), the effect must be on the NGC transmission system, and in the case of an event on the NGC transmission system, the effect must be on a user(s) system(s) (other than on an embedded small power station or embedded medium power station).

Where NGC has determined that an event is a joint system incident, NGC shall, as soon as possible, notify all relevant users that a joint system incident has occurred and, if appropriate, that it has established an incident centre and the telephone number(s) of its incident centre if different from those already supplied pursuant to joint system incident.

### *X.2.4 Isolating the generating unit from the network*

In **Sweden and Denmark**, 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 power changes (upwards or downwards), and then achieving stable operation and normal power control capability.

For the implementation of isolation in the **UK**, the following agreement of the safety precautions in accordance with requesting safety co-ordinator the implementing safety co-ordinator shall then establish the agreed isolation.

The implementing safety co-ordinator shall confirm to the requesting safety co-ordinator that the agreed Isolation has been established, and identify the requesting safety co-ordinator's HV apparatus up to the connection point, for which the isolation has been provided.

In the event that parts of or all of the company's transmission system become disconnected from the NGC transmission system, the obligation to control system frequency on such disconnected parts may be delegated by NGC to the company as appropriate.

For the agreement of isolation, the implementing safety co-ordinator shall then inform the requesting safety co-ordinator of the following:

For each location, the identity (by means of circuit name, nomenclature and numbering position) of each point of isolation.

Whether isolation is to be achieved by an isolating device in the isolating position or by an adequate physical separation.

In **India**, no part of the grid shall be deliberately isolated from the rest of the regional grid, except:

1) Under an emergency, and conditions in which such isolation would prevent a total grid collapse and/or enable early restoration of power supply.
2) When serious damage to costly equipment is imminent and such isolation would prevent it.
3) When such isolation is specifically instructed by RLDC. Complete synchronization of grid shall be restored as soon as the conditions again permit it. The restoration process shall be supervised by RLDC, as per operating procedures separately formulated.

Upon reaching 47.5 or 51.5 Hz, the generating unit may disconnect from the **German** network. In the event of a loss of steady state or transient stability, the generating unit shall disconnect automatically from the network in order to avoid repeated slipping.

At a almost system voltage 85 % of the reference voltages (380/220/110 kV) on the high voltage side of the generator transformer (interface network generating unit), the generating unit may be disconnected from the network in order to allow secure tripping on auxiliary supplies.

With falling network voltage and a risk of generator overload, the generator transformer shall be adjusted, according to the TSOs specifications, in the direction of a lower transmission ratio, and the active power output shall be reduced.

Should the system frequency increase to a value of more than 50.5 Hz, ENE may demand lowering or the active power output according to figure 10.1 as additional requirement.

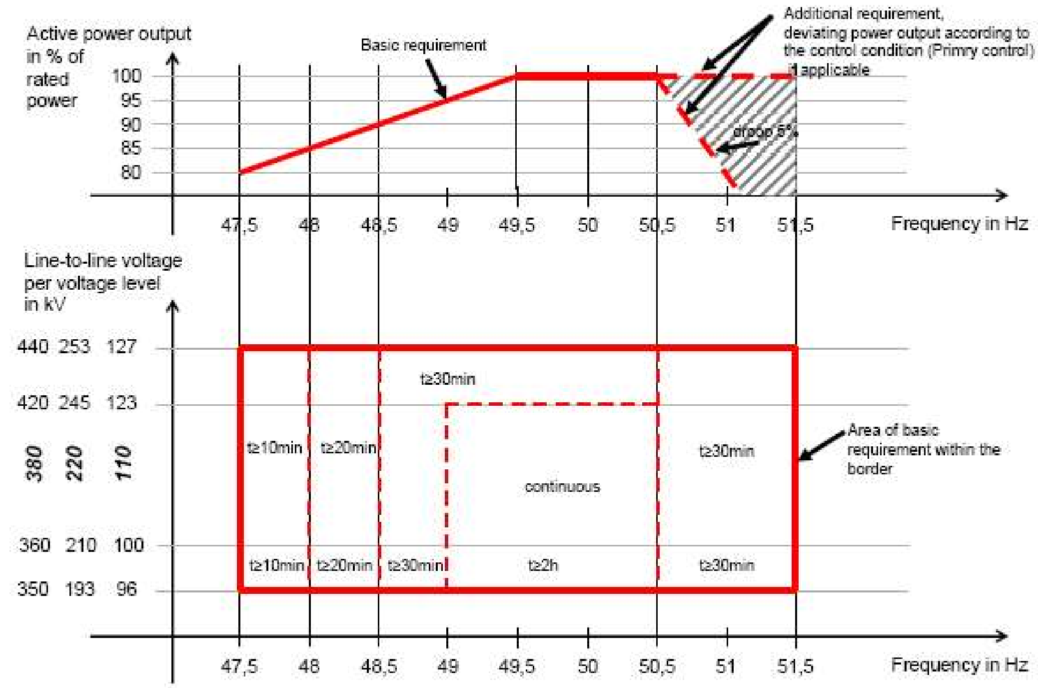



Figure 10.1 Requirements on the output power of the generating units to the German network for certain periods as a function of network frequency and network voltage (quasi-static consideration, i.e. frequency gradient 0.5 % minutes; voltage gradient 5 % minutes)

If the voltage at the network connection point drops to a quasi-static value of less than 80 % of the network voltage relative to the voltage prior to the drop, automatic isolation of the generating unit from the network may occur after 3 seconds at the earliest and must occur not later than after 5 seconds.

### X.3 Operational Planning and management

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.

In **Denmark and Sweden**, future operational aspects shall be taken into account in the planning of the Nordel 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 planning criterion in **India** is based on the security philosophy on which the ISTS has been planned. The security philosophy may be as per the transmission planning criteria and other guidelines as given by CEA[17]. The general policy shall be as detailed below:

1) As a general rule, the ISTS shall be capable of withstanding and be secured against the following contingency outages without necessitating load shedding or rescheduling of generation during steady state operation :

    Outage of a 132 kV D/C line.
    Outage of a 220 kV D/C line.
    Outage of a 400 kV S/C line.
    Outage of single interconnecting transformer.
    Outage of one pole of HVDC bipole line.

[17] CEA.- Central Electricity Authority

Outage of 765 kV S/C line.

2) The above contingencies shall be considered assuming a pre-contingency system depletion (planned outage) of another 220 kV D/C line or 400 kV S/C line in another corridor and not emanating from the same substation. All the generating units may operate within their reactive capability curves and the network voltage profile shall also be maintained within voltage limits specified.

Any one of these events defined above shall not cause:

Loss of supply.
Prolonged operation of the system frequency below and above specified limits.
Unacceptable high or low voltage.
System instability.
Unacceptable overloading of ISTS elements.

Shutdown planning of power stations in **Germany** and disconnections in the extra-high voltage level which have an impact on power plant generation scheduling need to be coordinated. In the framework of operational planning, the TSOs shall agree with power plant operators the overhaul schedules of generation plants. The TSO shall co-ordinate this decommissioning with the planned disconnections in the extra high voltage system, and agree with the power station operator upon binding dates in this respect.
Planning of temporary or final shutdown of generating units shall be agreed early enough, if possible 2 years prior to the shutdown, with the TSO so as to enable technical contingency measures to be implemented on the network in due time.

### *X.4 System Management*

The most important functions of system management of the transmission system include network monitoring, the assurance of network security, the requesting and performance of switching operations, the performance of voltage/reactive power and power/frequency control operations, and the commissioning and maintenance of the requisite facilities for metering and pricing between system operators and connection users.

The system service of system management includes all tasks performed by the TSO as part of coordinated commitment of the generating units in **Germany** (e.g. for frequency stability) and of network management, and of national/international interconnected operation by central control centers which are independent and act on their own responsibility. System management also includes all measures for the creation and operation of the requisite metering technology and for billing of all services performed.

All limit values must be adhered to under normal operation, e.g.

Adherence to the maximum and minimum permissible voltages, maximum currents on the network equipment, and agreed system short circuit powers on the individual network nodes and the interfaces.
Selection of a voltage profile in the network which is as balanced as possible and generally high, and consequently reduction of the transmission losses and improvement in stability.

Should the TSO employ voltage/reactive power optimization involving information from subordinate or same voltage networks, co-ordination is realized in this respect at the different interfaces:

Provision of measured values from joint sensors.
Corrective intervention in the case of a violation of a voltage limit by the TSO or connection user responsible for the violation.
Automatic rejection of the optimization result in the case of large step type voltage changes resulting from the optimization (for example due to measurement errors); the responsible administrative body shall be informed.
Provision of regional/local reactive power reserves.

In peak-load/low-load cases, the TSO will take measures of its own or maintain measures contractually in order to counter the drop/rise in voltage. This affects:

The operation of compensation equipment (e.g. shunt reactors, capacitor banks, Flexible AC Transmission Systems (FACTS)).
Tapping of transformers.
Provision of reactive power from generating units and synchronous condensers, overexcited (under excited).
Line switching.
Disconnection of contractually agreed loads.

Disturbances in the **German gird** exceeding the (n - 1) criterion may impair the frequency and voltage stability of the transmission system owing to deviations in the active and/or reactive power balance, and may lead to network sectionalizing and local interruptions of supply.

The following 5 stage plan shall apply for load shedding as a function of the frequency to avoid total blackouts:

Stage 1: 49.8 Hz alerting of personnel, scheduling of the power station capacity not yet activated.
Stage 2: 49.0 Hz Instantaneous load shedding of 10 - 15 % of the system load.
Stage 3: 48.7 Hz Instantaneous load shedding of a further 10 - 15 % of the system load.
Stage 4: 48.4 Hz Instantaneous load shedding of a further 15 - 20 % of the system load.
Stage 5: 47.5 Hz Disconnection of the power stations from the network.

In Stage 1, the power station and network personnel shall be informed so that they are able to respond quickly and appropriately to the situation. In addition, the generation capacity available at short notice, including that which is not available under primary and/or secondary control, shall be activated and generating units with fast-start capability connected to the network. Attention shall be paid here to the transmission capacity of the network.

Stages 2, 3 and 4 are intended to ensure that selected load shedding does not reach stage 5, and that disconnection of the generating units from the network is thereby avoided. Stage 5 has the function of ensuring generating unit auxiliary supplies and operation of the generating units for rapid commitment for the purpose of restoration of supply and the avoidance of damage to the power stations.

The system management function also includes the operational implementation of the power exchange agreed on the basis of schedules of the BGMs, the generation schedules for power stations in accordance with the requirements for secondary control power, and the activation of minutes reserve and, if necessary, emergency reserve. Essential functions here include congestion forecasting, congestion management, load forecasting for the control area, observation of the instantaneous deployment of the power stations, and the co-ordination or utilisation of ancillary services for the provision of system services.

### *X.5 Restoration*

In **India**, procedures shall be developed to recover from partial/total collapse of the grid and periodically updated in accordance with the following requirements. These procedures shall be followed by all the regional constituents to ensure consistent, reliable and quick restoration.

1) Detailed plans and procedures for restoration of the regional grid under partial/total blackout shall be developed by RLDC in consultation with all regional constituents/REB secretariat and shall be reviewed/updated annually.

2) Detailed plans and procedures for restoration after partial/total blackout of each constituents system within a region, will be finalised by the concerned constituent in coordination with the RLDC. The procedure will be reviewed, confirmed and/or revised once every subsequent year.

3) List of generating stations with black start facility, inter-state/inter regional ties, synchronising points and essential loads to be restored on priority, should be prepared and be available with RLDCs.

4) The RLDC is authorised during the restoration process following a black out, to operate with reduced security standards for voltage and frequency as necessary in order to achieve the fastest possible recovery of the grid.

5) All communication channels required for restoration process shall be used for operational communication only, till grid normalcy is restored.

Disturbance and fault situations in the **German grid:**

Failure solely of the operator’s own transmission system, and voltage supply from other transmission systems.
Additional failure of the interconnecting lines and of the surrounding transmission system.
Widespread collapse of the transmission systems with islanding beyond the boundaries of the control area.

Measures taken during restoration of supply:

Restoration of supply to the nuclear power plants.
Coupling of available power stations with in-circuit network parts.
In order to increase the stability, a low voltage level shall be maintained prior to the connection of lines.
The TSOs shall communicate the busbar voltages of the remote stations to each other.
Synchronizers.

Failure of the operator’s own transmission system without restoration support from other transmission systems:

Dead parts of the network must also be re-energized from available power plants or storage stations with black start capability and/or gas turbines.

The load must be connected in sufficiently small steps, at least in the initial phase.

Restoration of supply in generating units in **Germany** must be designed for reliable tripping onto auxiliary supplies from any working point permitted by the generator output diagram, see figure 10.2.

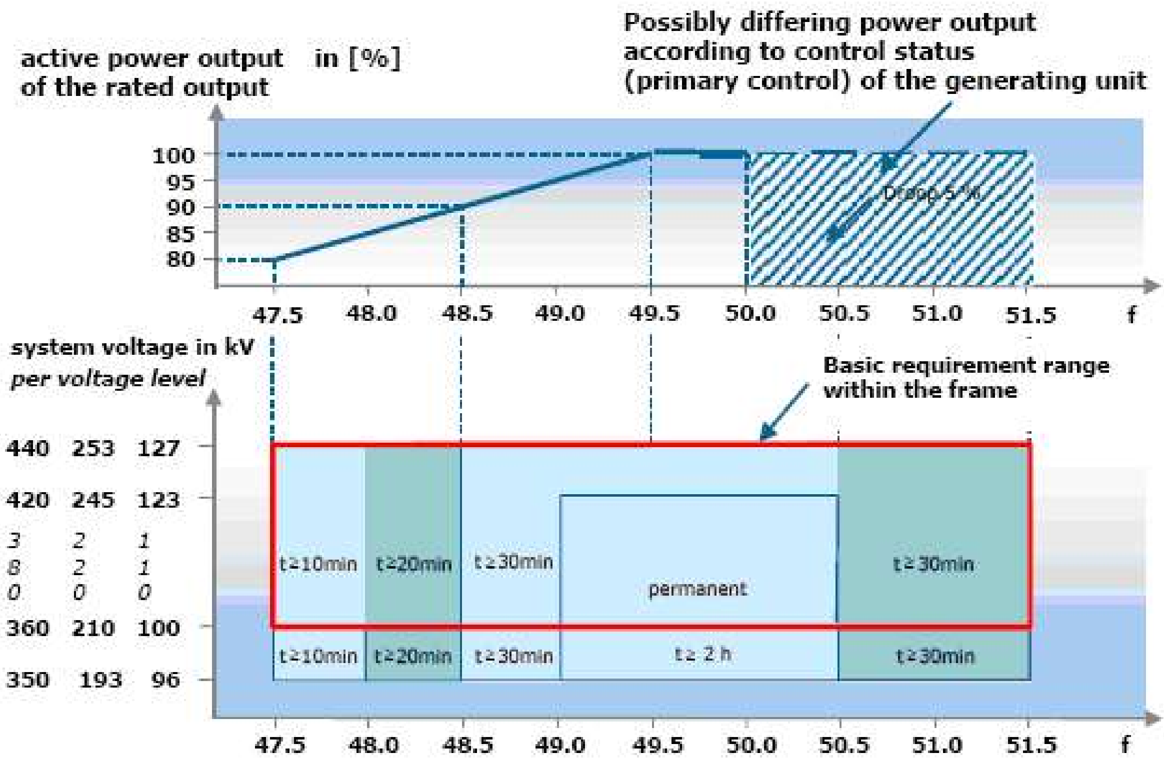



Figure 10.2 Requirements upon from generating units to the German network to be guaranteed for specific periods as a function of the network frequency and network voltage (almost static consideration, i.e. frequency gradient 0.5 % minutes; voltage gradient 5 % minutes).

### *X.6 Emergency*

In emergency situations, there may be circumstances where safety precautions need to be established in relation to an unintended electrical connection or situations where there is an unintended risk of electrical connection between the transmission system and a user's system, for example resulting from an incident where one line becomes attached or unacceptably close to another.

For emergency manual disconnection in the **UK**, each network operator will make arrangements that will enable it, following an instruction from NGC, to disconnect customers on its user system under emergency conditions irrespective of frequency within 30 minutes. It must be possible to apply the demand disconnections to individual or specific groups of grid supply points, as determined by NGC.

The relevant safety co-ordinator shall be that for the electrically closest existing connection point to that user's system or such other local connection point as may be agreed between NGC and the user, with discussions taking place between the relevant local safety co-ordinators.

# XI. Maintenance and communication

Planning and maintenance are coordinated between the respective operational managements in **Sweden** and **Denmark**. The operational planning and maintenance which affects the entire Nordic system shall, whenever possible, be coordinated in consultation with all system operators.

In **South Africa** participants shall operate and maintain the equipment owned by them. Participants shall monitor the performance of their plant and take appropriate corrective action where deteriorating trends are detected. Maintenance scheduling shall be done in accordance with the system operation code.

In **Germany**, ENE and the connectee are each responsible for the maintenance of equipment and system components situated in their respective properties. All system components must be maintained according to the state of the art to guarantee proper operation.

## *XI.1 Operational communication*

"Operators of long transmission lines require reliable communications for control of the power grid and, often, associated generation and distribution facilities. Fault sensing protection relays at each end of the line must communicate to monitor the flow of power into and out of the protected line section."[18]

In **Germany**, technical facilities must be provided for exchange of information in real time.
Power station operator to TSO:

> Circuit breaker/disconnector/earthing disconnector/step switch settings, insofar as they are required for operation or for system analyses.
> Measured values of the current operating mode (active and reactive power).

TSO to power station operator:

> Reference values for control and instantaneous demand value of the secondary control.
> Reference value of the reactive power in the form of schedule or as an instantaneous value. Circuit breaker/disconnector/earthing disconnector settings, insofar as they are required for operation of the generating unit.

Each generating unit or group of generating units in **Germany** which is to be operated under the secondary controller of a TSO, must be integrated online into the corresponding secondary control circuit. The control cycle is 3 seconds, so that a shorter interval of measured values' renewal is required.

### *XI.1.1Performance requirements for communications circuits*

The requirements in **New Zealand** are:

1) During a loss of communication with generators.

   For a loss of communication with the system operator lasting at least five minutes, generators must use reasonable endeavours:

[18] http://en.wikipedia.org/

For synchronised generating units, take independent action to adjust supply to maintain frequency as close as possible to the normal band, and maintain voltage as close as possible either to that previously advised by the system operator or as can be best established by the generator.

Synchronise and connect available generating units.

Continue to attempt to maintain frequency and voltage.

As soon as practicable after communications are restored, report to the system operator on the action taken.

2) During a loss of communication with ancillary service agents.

For a loss of communication with the system operator lasting at least five minutes, ancillary service agents must use reasonable endeavours:

If on load, take independent action to adjust any real or reactive power resources to maintain frequency and voltage as close as possible either to that previously advised by the system operator or as can be best established by the ancillary service agent.

Connect available reactive capability resources.

Continue to attempt to maintain the voltage.

As soon as practicable after communications are restored, report to the system operator on the action taken.

3) Major disruption to system operator communications and operational control centre facilities.

In the event of a failure at the system operator's operational centre that disables the main dispatch or communication systems, the system operator may temporarily transfer its operational activities to an alternative operational centre, and the system operator will arrange for communication facilities transfer to the new location and will notify participants of these arrangements.

### *XI.1.2Supervisory Control and Data Acquisitions (SCADA) Requirements*

In the **USA**,  SCADA indication of real and reactive power flows and voltages levels is required. All substations with a 41.6 kV or greater circuit breaker and all generation 5 MW or greater shall provide SCADA for the circuit breaker to the control area operator. The following equipment data and statuses must be provided in a 6 second or less response periodicity to the control area operator:

Breaker position.
Motor operated disconnect position.
Transmission line flow and alarming.
Bus voltage and alarm battery and associated equipment status.
Protective relaying AC and DC voltages status.
Transformer and associated equipment status.
Lock out relay status.
Capacitor/reactor status.
Other points as necessary to provide control and indication.

## XI.2 Measurements / Metering

Metering is required for all interconnections to the electric system. Metering must be designed such that load can be identified separately from the generator output. Such net output is the kWh output of the generator less the generation station auxiliary load.

The metering installation in the **USA** shall be electrically connected on the line side of the main disconnect thus allowing the meter to be read even when the generator is not running. For substation metering, the meter may be located on the low side of the step-down transformer, but the meter must be able to compensate for transformer energy losses from the high side of the transformer.

### XI.2.1Performance requirements for indications and measurements

In **India**, each regional constituent shall provide adequate and reliable communication facility internally and with other constituents/RLDC to ensure exchange of data/information necessary to maintain reliability and security of the grid. Wherever possible, redundancy and alternate path shall be maintained for communication along important routes, e.g. SLDCs to RLDC.

The regional constituents shall send information/data including disturbance recorder/sequential event recorder output etc. to RLDC for purpose of analysis of any grid disturbance/event. No regional constituent shall block any data/information required by the RLDC for maintaining reliability and security of the grid and for analysis of an event.

ENE in **Germany** is responsible for the proper transfer metering facilities and provisions of the metered values as required by law.

The current transformers on the metering points are equipped with separate cores for protection, measurement and metering. If required in technical terms, the current transformers have separate windings.

Where required for operational functions, metering facilities shall be installed in such a way that it is possible to provide metered values at short cycle measurement periods (< 15 minutes), and/or to provide metering impulses.

### XI.2.2Telemetry

In **South Africa**, All participants shall be permitted to have telecontrol equipment in the substations, yards or buildings of the other participants to perform agreed monitoring and control.

The requirements in the **USA** for telemetry are based on the need of the system control center to protect all users of the transmission and distribution system for unacceptable disturbances. The need for requiring telemetry may include the ability to monitor the following conditions:

1) Detecting facility back feed onto otherwise de-energized lines.
2) Providing information necessary for reliable operation of the electricity company's equipment (feeders, substation, etc.) during normal emergency operation.
3) Providing information necessary for the reliable dispatch of generation.

Telemetry is required by the electric company when:

The possibility of islanding a portion of the electricity system exists ( typical of smaller feeders).
1 MW or larger generation becomes a significant portion of a feeder's total load (typically 6 to 10 MW).
There is the potential for multiple applicants to have generators on the same substation and/or feeders.
There is the potential for back feeding onto the electricity system or islanding a portion of the electric system.
The facility plans to provide its own ancillary services.
There is intent to sell power and energy over the electricity company's facilities.
The facility is required to meet the manual load shed requirement.
41.6 or 69 kV substations are equipped with circuit breakers on for all substations classified at 115 kV and above.
FERC requires telemetering for normally open or emergency tie connections.

If "islanding" is a possibility, it will be identified during the interconnection study process. In such instances, the following telemetry may be required:

Real and reactive power flow for each generator (kW and kvar).
Voltage representative of the electricity company service to the facility.
Status (open/close) of facility and interconnection breaker(s).
Position of incoming and tie breakers or switches.
Energy output of the generators (kWh).
Applicant load from the electricity company's service (kW and kvar).

### *XI.2.3* ***Event recorder***

The **UK** operating safety co-ordination utilizes a Record of Inter-System Safety Precautions (RISSP) to record the implementation of safety precautions.

All unattended generation facilities in the **USA** with capability greater than 1 MW and with automatic or remotely initialed paralleling capability must have an event recorder that will enable the electricity company to make an after the fact determination of the status of the generation facility at the time of a system disturbance, should such determination be required.

The generation facility operator shall ensure that such time reading is correct and synchronized to an accurate time standard. The event recorder or other recording device(s) at the generation facility must be capable of providing:

1) A record of the time of any relay operations and targets of the relay that caused the generation facility to separate.
2) If applicable, the time of any paralleling with and separations from company's electricity system.
3) The time of the change in voltage control device set points (if applicable).
4) The time of change in the operating status (i.e., opened or closed) of any other voltage control device (i.e., shunt capacitors or reactors).

In addition, for generating facilities with a nameplate rating equal to or greater than 10 MW, the event recorder must also provide a record of deliveries to the electric itypower company of real power in kW and reactive power in kvar and output voltage in kV.

### *XI.3 Electric time and time error*

The **UK** national grid company will endeavour to control electric clock time error to within plus or minus 10 seconds by specifying changes to target frequency. Errors greater than plus or minus 10 seconds may be accepted temporarily at national grid company's discretion. NGC will give 15 minutes notice of variations in target frequency.

### *XI.4 System test*

System tests involve the controlled application of irregular, unusual or extreme conditions of equipment, the total system or any part of the total system.

The system operator in **South Africa** may issue an instruction requiring a generator to carry out a test to demonstrate that the relevant power station complies with the grid code.

In the **UK,** the objective for system tests is to ensure that there is no threat in the safety of either their personnel or the general public, they should cause the minimum threat to the security of supplies, to the integrity of plant and/or apparatus, and cause minimum detriment to NGC and users.

The system tests proposed should be carried out either by:

> A user which may have an effect on the total system or any part of the total system (in addition to that user's system) including the NGC transmission system.
> By NGC which may have an effect on the total system or any part of the total system (in addition to the NGC transmission system).

During the commissioning process for an UK CCGT plant, the NGC specifies those tests which it reasonably feels will demonstrate the performance of the plant. Three typical tests which NGC witnesses are:

1) Excitation system tuning/optimisation. It is necessary to validate the performance of the excitation system and to verify its dynamic model which is used in system stability studies. Typically this process involves:

    Open circuit step responses (2 - 5 %) to tune the AVR.
    On load step responses (1 - 2 %) and random noise Injection to tune and optimise the performance where a power system stabilizer is required.
    On load step responses to validate the dynamic performance of over and under excitation limiters.

2) Governor system performance. This requires a series of step and ramp injections into the plant governor to demonstrate its performance. As with the excitation system NGC verifies site test results against the dynamic model supplied by the generator. The sequence also requires a full load rejection to demonstrate the over speed control of the governor.

3) Reactive capability test. Each unit is required to demonstrate its 0.95 lead / 0.85 lag capability in turn. During this test system voltage control is generally achieved by balancing the net Mvar output on the remaining elements of the CCGT.

# XII. Conclusions

As part of this project we made an analysis of the different grid codes emitted by the organisations entrusted to regulate the electrical sector in each of the countries that were selected.

Inside this selection of countries there is at least one representative country of every continent, this with the purpose of comparing the different technical specifications of grid codes around the world, an important factor is that not all the grid codes are emitted in the same period of time, there are countries like South Africa that took as reference the grid codes of other countries.

For the first part we present a table for each chapter, which contains the most relevant specifications, it is important to note that just because a country does not have a requirement checked, it doesn't mean that they don't consider it, it is just that their grid code does not have a specific section about it.

| Generating units | U.S.A. | U.K. | New Zealand | Germany | Denmark | South Africa | India | Sweden |
|---|---|---|---|---|---|---|---|---|
| Non hydro and hydro units | | | | | | X | | |
| Thermal units | | | | | X | X | | X |
| Nuclear power stations | | | | X | X | X | | X |
| Stability of transmission systems | X | X | X | X | X | X | X | X |
| Synchronization | X | X | X | X | | | X | |
| Power system stabilizers | X | | | X | X | | | X |

Table 12.1 Generating unit's comparison

During the analysis of the information obtained as for the specifications in the generating units as you can see in the Table 12.1, some of the countries that we selected have nuclear plants for their electricity generation system, but inside the grid code there is no specific information for the case of India and United States of America, regarding United Kingdom's grid code, it only refers to the functioning periods and the characteristics of the reactor, but it never refers to the safety measurements and there are no technical specifications about connection conditions into the transmission network.

Due to the global electricity market, nowadays the stability is a very important topic for the transmission system operators, reason why all the grid codes analyzed have detailed specifications.

The specifications about the generation units are done in function to the type of generating unit available for each country. It is important to mention that in the previous table only the countries that have specific regulations for each of the types of generation are marked, the rest of them make general reference to the procedure of regulation of their generating units

| Network conditions | U.S.A. | U.K. | New Zealand | Germany | Denmark | South Africa | India | Sweden |
|---|---|---|---|---|---|---|---|---|
| Isolation | X | X | | X | X | | X | X |
| Back up protection for grid faults | | X | X | X | X | X | | X |
| Emergencies | X | X | | X | X | | X | X |
| Extra high voltage | | | | X | | | X | |
| Neutral | X | X | | X | | | | |
| HVDC | | | X | X | X | | X | X |

Table 12.2 Network conditions comparison

The grid codes are the technical specifications between the generation and the transmission network. For this reason all the grid codes that were analyzed speak in detail of network conditions.

Different types of faults exist, for that reason it is necessary to implement back up protection to increase the security in the system (see Table 12.2), especially for the nearby faults, for Germany, New Zealand and UK their protective equipment must be agreed between the TSOs and the power station operators. On the other hand, South Africa, Denmark and Sweden requirement standards are determinated by the transmission system operator.

Only some countries refer to the HVDC, because not all the countries have this type of technology for transmitting electric power.

| Frequency | U.S.A. | U.K. | New Zealand | Germany | Denmark | South Africa | India | Sweden |
|---|---|---|---|---|---|---|---|---|
| Frequency support | | X | X | X | X | X | | X |
| Capabilities | X | X | X | X | | | X | |
| Governors | X | X | X | | | X | X | |
| Frequency control | X | X | X | X | X | | | X |
| Response to low frequency | X | X | X | X | X | X | | X |
| Response to high frequency | | X | X | X | X | X | | X |
| Control reserve | | X | X | X | X | | | X |
| Primary control | X | | | X | X | | | X |
| Secondary control | | | | X | | | | |

Table 12.3 Frequency comparison

The frequency requirements are an essential part in all the grid codes as you can see in the Table 12.3. There are different permissible variations of the frequency. During normal state almost all the countries have the same parameters (49.5 to 50.5 Hz) except Sweden and Denmark who considerer a 49.9 to 50.1 Hz, India always remains within 49 to 50.5Hz.

In order that stability exists between the generation and the transmission system network it is necessary to control the possible variations in the frequency, having fulfilled the comparison among the different grid codes, South Africa and India only refer to the required equipment to be able to control the frequency, the rest of the countries have more detailed specifications when it comes to frequency control.

The dead band is where no action occurs, the maximum allowable dead band values for UK and India are the same (0.15 Hz), the countries who are more strict with this value are Denmark and Sweden (0.05 Hz) we don't compare this values with USA (0.036 Hz) because the nominal frequency value is different, but it is also a strict deadband.

| Voltage and reactive power | U.S.A. | U.K. | New Zealand | Germany | Denmark | South Africa | India | Sweden |
|---|---|---|---|---|---|---|---|---|
| **Connection conditions** | | X | X | X | X | X | | X |
| **Active power** | | X | | X | X | | | X |
| **Reactive power** | X | X | X | X | X | X | X | X |
| **Reactive capabilities** | | X | X | | X | | | X |
| **Power factor** | X | X | | X | X | X | | X |
| **Voltage control** | X | X | X | X | X | | | X |
| **Automatic voltage regulation** | | | | | | X | X | |
| **Voltage stability** | X | X | | X | | | | |

Table 12.4 Voltage and reactive power comparison

The permissible variation regarding voltage (i.e. 110 kV) is of 10% of normal voltage, this is a determinate condition for the entire grid codes as you can see in the Table 12.4, only German grid code has a permissible variation of 11% of the nominal value.

In power transmission and distribution, significant efforts are made to control the reactive power flow, for that reason all grid codes have special requirements. This is typically done automatically by switching inductors or capacitor banks and other components throughout the system to control reactive power flow for the reduction of losses and stabilization of system voltage.

The power factor plays a very important role when it comes to customers, since they can be financially penalized for having low power factor loads (especially larger customers).

| Quality | U.S.A. | U.K. | New Zealand | Germany | Denmark | South Africa | India | Sweden |
|---|---|---|---|---|---|---|---|---|
| **Voltage quality** | | X | | | X | | | X |
| **Voltage collapse** | | | | X | X | X | | X |
| **Voltage dip** | X | | | | X | | | X |
| **Flicker** | X | X | | | X | | | X |
| **Harmonics** | X | X | | | | | | X |

Table 12.5 Quality comparison

Nowadays the quality concept is applied everywhere in daily life and electricity is not any exception. Because of the deregulation process, there are more participants into the electricity market, so in order to compete with the other markets, quality in electricity is very important.

Assuring the quality at the connection is not an easy task; for that reason the grid code specifies technical requirements to reduce the variables (quality defects) between the generation and the transmission (see Table 12.5).

Denmark and Sweden are the countries which pay more special attention regarding quality and reliability, India and New Zealand only refer to general specifications about this topic.

All the countries have different parameters for their quality requirements, for example USA has a 2.5 % of the total harmonic distortion for voltages between 69 kV and 115 kV and the Swedish standard is 0.5 % for the systems above 110 kV. It is important to mention the nominal voltage for customer use in the USA is 120 V (60Hz) and in Sweden is 230V (50Hz).

| Protection requirements | U.S.A. | U.K. | New Zealand | Germany | Denmark | South Africa | India | Sweden |
|---|---|---|---|---|---|---|---|---|
| **System requirements** | X | X | X | X | X | X | X | X |
| **Criterion (n - 1)** | | | | X | X | X | | X |

Table 12.6 Protection requirements comparison

All the grid codes emitted for the different countries have specifications relating their protection requirements as we refer in the Table 12.6, this is done in order to diminish the risk of damaging their equipment in case of a fault, depending on the type of faults, special equipment is mentioned too, these specifications not only speak about protection for the units of generation but also the safety procedures for the operation of the transmission systems.

| Contingency planning | U.S.A. | U.K. | New Zealand | Germany | Denmark | South Africa | India | Sweden |
|---|---|---|---|---|---|---|---|---|
| Planning and development | | | X | X | X | X | | X |
| Transmission plan | | | | X | X | X | X | X |
| Recovery procedures | | X | | X | | | X | |
| Black starts | | X | | X | X | X | X | X |
| Re-synchronization of islands | | X | | | X | | | X |
| Joint system incident procedure | | X | | | | | | |
| Operational planning and management | | | | X | X | | X | X |
| Restoration | X | | | X | X | | X | X |

Table 12.7 Contingency planning comparison

Not only a grid code must contain the technical requirements as you can see in the Table 12.7, but also it must have specifications for when a contingency happens, that is to say, in case of unacceptable situations there must be recovery procedures so material and economic losses are avoided.

For example, restoring power after loss of the electricity supply can be difficult, as power stations need to be brought back on line. Normally, this is done with the help of power from the rest of the grid. In the absence of grid power, a so-called black start needs to be performed in order to restart a generating station and restoring power to the grid after a large scale power outage or disaster.

| Maintenance and communication | U.S.A. | U.K. | New Zealand | Germany | Denmark | South Africa | India | Sweden |
|---|---|---|---|---|---|---|---|---|
| Network maintenance | | | | X | X | X | | X |
| Operational communication | X | X | X | X | X | | X | X |
| Measurements and telemetry | X | X | X | X | | X | X | |

Table 12.8 Maintenance and communication comparison

Inside a global market in which there are different participants, it is important that communication exists among them, since in the event of a possible fault, necessary precautions can be taken as you can see in the Table 12.8.

Nowadays different reviews are being made to reinforce the grid codes with the technical specifications for renewable energies, especially wind power.

## XII.1 Optimal grid code

The optimal grid code is intended to establish the reciprocal obligations of all participants who are part of the transmission system operator. It is important to mention that this grid code contains the minimum requirements, which can change according to the needs of every country that applies it.

The grid code shall ensure the following:

**Planning code** that provides for the supply of information for planning and development studies:

**Connection conditions** which specifies a minimum of technical, design and operational plant criteria, regarding:

1) **Generating units**

   Non hydro and hydro units
   Thermal units
   Nuclear power stations
   Stability of transmission systems
   Synchronization
   Power system stabilizers

2) **Renewable energies**

   Voltage
   Frequency control
   Active and reactive power
   Isolation
   Quality

3) **Network conditions**

   Isolation
   Back up protection for grid faults
   Emergencies
   Extra high voltage
   Neutral
   HVDC

4) **Frequency**

   Frequency support
   Capabilities
   Speed governors
   Frequency control
   Response to low frequency
   Response to high frequency
   Control reserve
   Primary control
   Secondary control

5) **Voltage and reactive power**

Connection conditions
Active power
Reactive power
Reactive capabilities
Power factor
Voltage control
Automatic voltage regulation
Voltage stability

6) **Quality**

Voltage quality
Voltage collapse
Voltage dip
Flicker
Harmonics

7) **Protection requirements**

Feeder protection
System requirements
Criterion (n-1)

8) **Contingency planning**

Planning and development
Transmission plan
Contingency
Black starts
Re-synchronization of islands
Joint system incident procedure

9) **Operational planning and management**

Restoration
Maintenance and communication
Network maintenance
Operational communication
Measurements and telemetry

**Operating code** contains details for high level operational procedures for example demand control, operational planning and data provision.

This grid code must be written in a language easy to understand; likewise it must rely on the whole nomenclature and necessary annexes.

In order that a grid code is functional it is required to be submitted to different reviews as well as update, and it is necessary for the grid code to fit according to the needs of every country.

## XII.2 Future work

Generation is any device producing (or releasing from storage) electrical energy. Such devices include rotating generators driven by steam turbines, internal combustion engines, or hydraulic turbines, windmills, photovoltaic arrays, fuel cells, battery arrays, or other energy sources with DC to AC inverter or any other electric generating device.

This document covers most of the technical requirements (grid codes) for the most common types of energy, but there is still much concern for the connection requirements for renewable energies.

If we take wind energy for example, the general philosophy for interconnecting early pilot and small commercial wind generation projects to the transmission grid was to disconnect them from the network in the events of disturbances or other problems, and allow reconnection only after normal conditions had again been established.

Today, in an environment of increasing cooperation and collaboration between the electric power engineering community and the wind power industry, various efforts have been launched to address the need for codification of the wind power plant requirements for successful interconnection with the transmission grid.

New renewable energies will very often need new infrastructure, perhaps in the future more research can be done concerning the grid code requirements to secure stable network operation and transportation of electricity, from renewable energy sites to the load centers.

# Appendix A

Below are the requirements for non-hydro and hydro units in South Africa as well as the basic line and generator protection devices for the USA.

| *Grid Code* requirement | | *Units* other than hydro (MVA rating) | | | | | |
|---|---|---|---|---|---|---|---|
| | | <20 | 20 to <100 | 100 to <200 | 200 to <300 | 300 - <800 | >=800 |
| GCR1 | Protection | | | | | | |
| | - Backup impedance | Yes | Yes | Yes | Yes | Yes | Yes |
| | - Loss of field | - | Depends on IPS Requirements | Yes | Yes | Yes | Yes |
| | - Pole slipping | - | Depends on IPS Requirements | Depends on IPS Requirements | Yes | Yes | Yes |
| | - Trip to house load | - | - | Depends on IPS Requirements | Depends on IPS Requirements | Yes | Yes |
| | - Gen trfr backup earth fault | Yes | Yes | Yes | Yes | Yes | Yes |
| | - HV breaker fail | Yes | Yes | Yes | Yes | Yes | Yes |
| | - HV breaker pole disagreement | Yes | Yes | Yes | Yes | Yes | Yes |
| | - *Unit* Switch-onto-standstill protection | Depends on IPS Requirements | Depends on IPS Requirements | Yes | Yes | Yes | Yes |
| | - Main protection only | Yes | Yes | Depends on IPS requirements | - | - | - |
| | - Main protection with self-monitoring or monitoring system or main and backup | - | - | [EIUG] Depends on IPS Requirements | Depends on IPS Requirements | - | - |
| | - Main and backup protection with self-monitoring or monitoring system | - | - | - | | Depends on IPS Requirements | Yes |
| | - Reverse power | Depends on IPS Requirements | Yes | Yes | Yes | Yes | Yes |
| GCR2 | Ability to island | | | Depends on IPS Requirements | Yes | Yes | Yes |
| GCR3 | Excitation system requirements | Yes | Yes | Yes | Yes | Yes | Yes |
| | - Power system stabiliser | - | - | Depends on IPS Requirements | Depends on IPS Requirements | Yes | Yes |
| | - Limiters | - | Depends on IPS Requirements | Yes | Yes | Yes | Yes |
| GCR4 | Reactive capabilities | Depends on IPS Requirements | Depends on IPS Requirements | Yes | Yes | Yes | Yes |
| GCR5 | Multiple *unit* tripping | If the total station output is greater than the single largest contingency as defined for instantaneous reserve | | | | | |
| GCR6 | Governing | Depends on IPS Requirements | Yes | Yes | Yes | Yes | Yes |
| GCR7 | Restart after station blackout | - | Depends on IPS Requirements | If the total station output is greater than the single largest contingency as defined for instantaneous reserve | | | If more than 1 *unit* at station |
| GCR8 | Black starting | - | If agreed | If agreed | If agreed | If agreed | If agreed |
| GCR9 | External supply disturbance withstand capacity | Depends on IPS Requirements | If more than 5 *unit* at station | If the total station output is greater than the single largest contingency as defined for instantaneous reserve | | | If more than 1 *unit* at station |
| GCR10 | On-load tap changing | - | Depends on IPS Requirements | Depends on IPS Requirements | Depends on IPS Requirements | Yes | Yes |
| GCR12 | Emergency *unit* capabilities | Depends on IPS Requirements | Depends on IPS Requirements | Yes | Yes | Yes | Yes |
| GCR11 | Independent action for control in system island | - | - | Depends on IPS Requirements | Yes | Yes | Yes |

Table 1 Applicable requirement to specific ratings for non-hydro units in South Africa.

| *Grid Code* requirement | | Hydro *units* (MVA rating) | | | | | |
|---|---|---|---|---|---|---|---|
| | | <20 | 20 to <100 | 100 to <200 | 200 to <300 | 300 - <800 | >=800 |
| GCR1 | Protection | | | | | | |
| | - Backup impedance | ] | Yes | Yes | Yes | Yes | Yes |
| | - Loss of field | - | Depends on IPS Requirements | Yes | Yes | Yes | Yes |
| | - Pole slipping | - | Depends on IPS Requirements | Depends on IPS Requirements | Yes | Yes | Yes |
| | Trip to house load | | | - | - | - | - |
| | - Gen trfr backup earth fault | Yes | Yes | Yes | Yes | Yes | Yes |
| | - HV breaker fail | Yes | Yes | Yes | Yes | Yes | Yes |
| | - HV breaker pole disagreement | Yes | Yes | Yes | Yes | Yes | Yes |
| | - *Unit* Switch-onto-standstill protection | | Depends on IPS Requirements | Yes | Yes | Yes | Yes |
| | - Main protection only | Yes | Yes | Depends on IPS requirements | - | - | - |
| | - Main protection with self-monitoring or monitoring system or main and backup | - | - | Depends on IPS Requirements | Depends on IPS requirements | - | - |
| | - Main and backup protection with self-monitoring or monitoring system | - | - | - | | Depends on IPS requirements | Yes |
| | - Reverse power | Depends on IPS Requirements | Yes | Yes | Yes | Yes | Yes |
| GCR2 | Ability to island | - | - | - | - | - | - |
| GCR3 | Excitation system requirements | Yes | Yes | Yes | Yes | Yes | Yes |
| | - Power system stabiliser | - | - | Depends on IPS Requirements | Depends on IPS requirements | Yes | Yes |
| | - Limiters | - | Depends on IPS Requirements | Yes | Yes | Yes | Yes |
| GCR4 | Reactive capabilities | Depends on IPS Requirements | Depends on IPS Requirements | Yes | Yes | Yes | Yes |
| GCR5 | Multiple *unit* tripping | - | Depends on IPS Requirements | If the total station output is greater than the single largest contingency as defined for instantaneous reserve | | | If more than 1 *unit* at station |
| GCR6 | Governing | Depends on IPS Requirements | Yes | Yes | Yes | Yes | Yes |
| GCR7 | Restart after station blackout | - | Depends on IPS Requirements | If the total station output is greater than the single largest contingency as defined for instantaneous reserve | | | If more than 1 *unit* at station |
| GCR8 | Black starting | - | If agreed | If agreed | If agreed | If agreed | If agreed |
| GCR9 | External supply disturbance withstand capacity | Depends on IPS Requirements | If more than 5 *unit* at station | If the total station output is greater than the single largest contingency as defined for instantaneous reserve | | | If more than 1 *unit* at station |
| GCR10 | On-load tap changing | - | Depends on IPS Requirements | Depends on IPS Requirements | Depends on IPS requirements | Yes | Yes |
| GCR10 | Emergency *unit* capabilities | Depends on IPS Requirements | Depends on IPS Requirements | Yes | Yes | Yes | Yes |
| GCR11 | Independent action for control in system island | - | - | Depends on IPS Requirements | Yes | Yes | Yes |

Table 2 Applicable requirements to specific ratings of hydro units in South Africa.

| Generator protection device | Device number | Less than 41.6 kV | 41.6 - 69 kV | 115 kV | 230 kV |
|---|---|---|---|---|---|
| Phase over current (Radial systems) | 50/51 | X | X | | |
| Ground over current (Radial systems) | 50/51N | X | X | | |
| Phase directional over current | 67 | | X[1] | X | |
| Ground directional over current or transformer neutral | 67N 50/51N | | X[1] | X | X |
| Distance relay zone 1 | 21Z1 | | | X[1] | X |
| Distance relay Zone 2 | 21Z2 | | | X[1] | X |
| Distance relay carrier | 21Z2C | | | X[1] | X |
| Ground directional over current carrier | 67NC | | | X[1] | X |
| Disatance relay carrier block | 21Z3C | | | X[1] | X |
| Pilot wire | 87L | | | X[1] | X |
| Permissive over reaching transfer trip (POTT) or hybrid | 21/67T | | | X[1] | X |
| Power fail trip[2] | 27 | | X[1] | X[1] | X[3] |
| Direct transfer trip | TT | | X[3] | X[3] | X[3] |

Table 3 Basic line protection devices in USA. (Protection needs to be redundant at 115 kV and above for all applications. For lower voltage systems, redundancy is only required for some specific areas of the system.)

[1] May be required depending on local circuit configuration.
[2] Power failure tripping may be required on load tie-line interconnection to facilitate restoration of customer load after a transmission line or area outage.
[3] Transfer trip may be required on interconnection depending on electricity company circuit configuration and loading, as determined by the electricity company typically, transfer trip is required on multi-terminal lines.
[4] Over current protection must be ble to detect a line-end fault. A phase instantaneous over current relay, which can see a line fault under sub-transient conditions, is required This is not required ifr a 51 V relay is used.
[5] For generation 400 kW or less, the under voltage requirement can be meet by the contactor under voltage release.

| Generator protection device | Device number | 40 kW or less | 41 - 400 kW | 401 KW and larger |
|---|---|---|---|---|
| Phase over current | 50/51 | X[4] | X[4] | |
| Over voltage | 59 | X | X | X |
| Under voltage | 27 | X[5] | X | X |
| Over frequency | 81O | X | X | X |
| Under frequency | 81U | X | X | X |
| Ground over voltage (ground fault protection for under ground system at the applicant's end) | 59G | TBD | TBD | TBD |
| Synchronizing and reclosing relays | 25 | TBD | TBD | TBD |
| Ground fault sensing scheme (utility grade) | 51N | | X[6] | |
| Over current with voltage restraint/voltage control or impedance relay | 51V<br>21 | | X[7] | |
| Reverse power relay | 32 | X[8] | X[8] | X[8] |
| Out of step | 68 | TBD | TBD | TBD |

Table 4 Basic generator protection devices in USA.

[6] For induction generators and certified non-islanding inverters aggregating less than 100 kW, ground fault detection is not required, for synchronous generation aggregating 40 kW, ground fault detection I required.
[7] A group of generators, each less than 400 kW but whose aggregate capacity is greater than 400 kW, must have an impedance relay or an over current relay with voltage restraint located on each generator greater than 100 kW
[8] For "self service" generator installations, under the proper system conditions, set of three single phase, very sensitive reverse power relays, along with the dedicated transformer may be used in lieu of ground fault protection. The relays shall be set to pick up on transformer magnetizing current, and trip the main breaker with in 0.5 seconds.

TBD.- To be determined on a project-by-project basis.

# Appendix B

The switchgear design diagrams for Germany and the transition schemes diagrams implemented for the USA can be observed below.

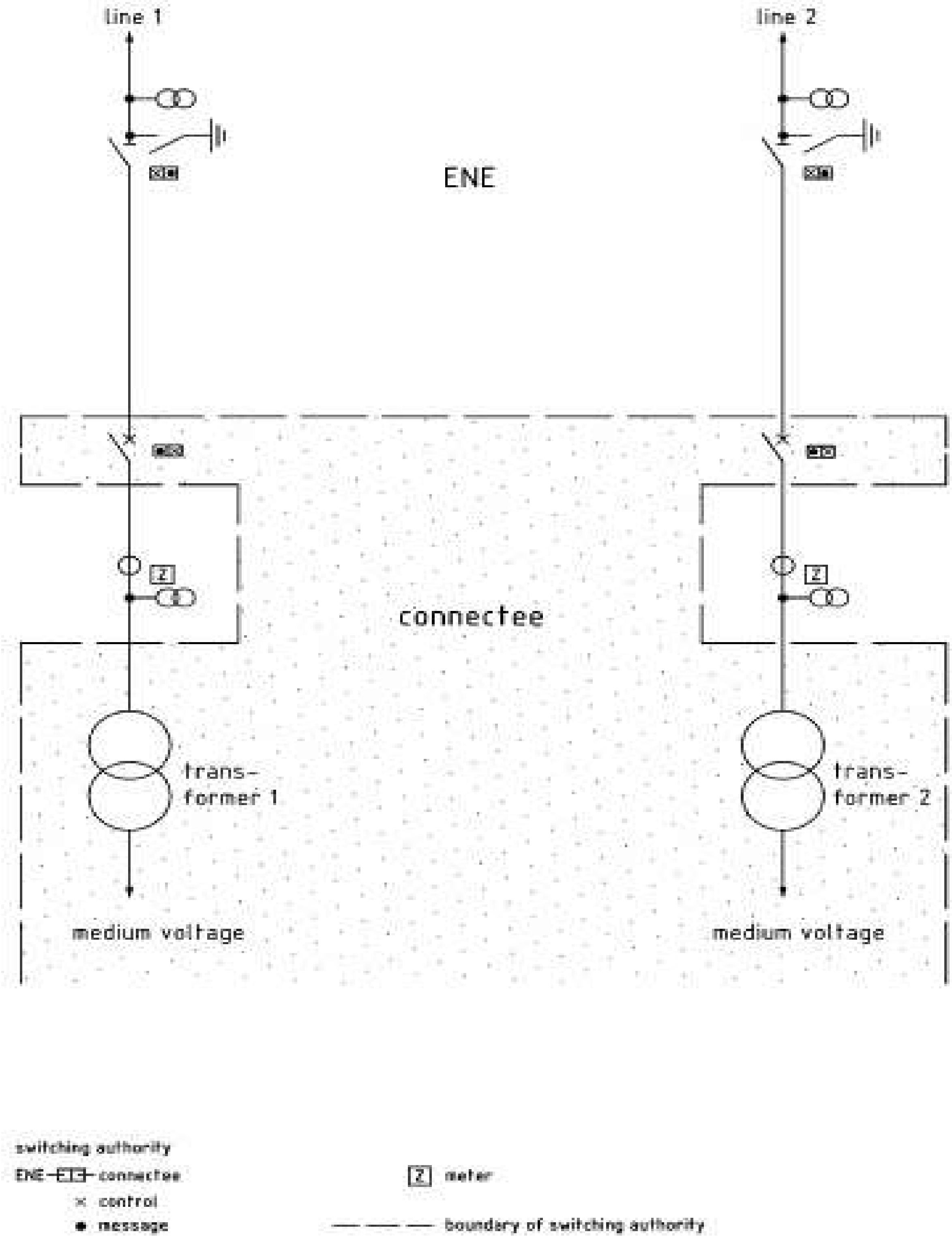



Figure 1 E - station.

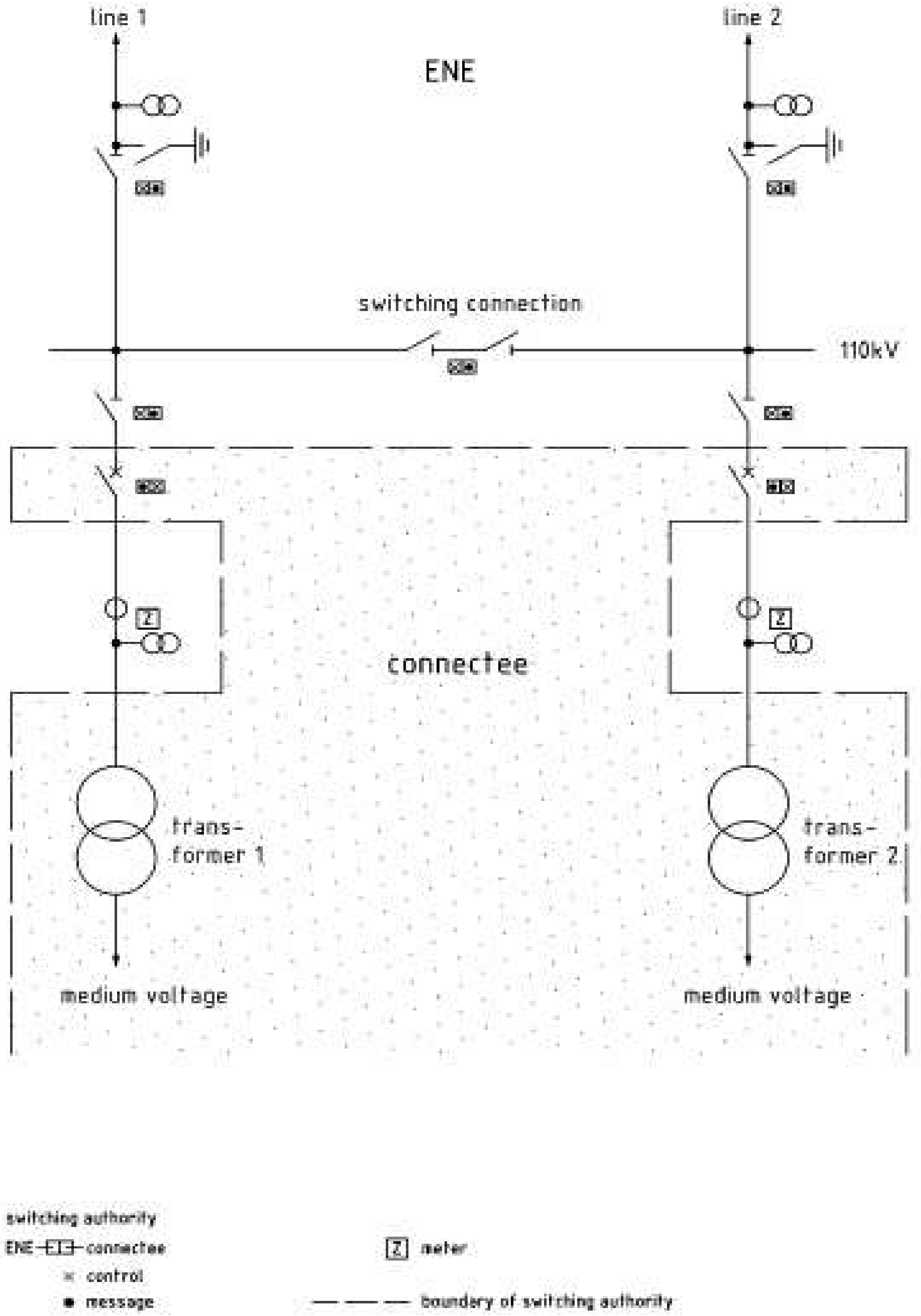



Figure 2 ES – station

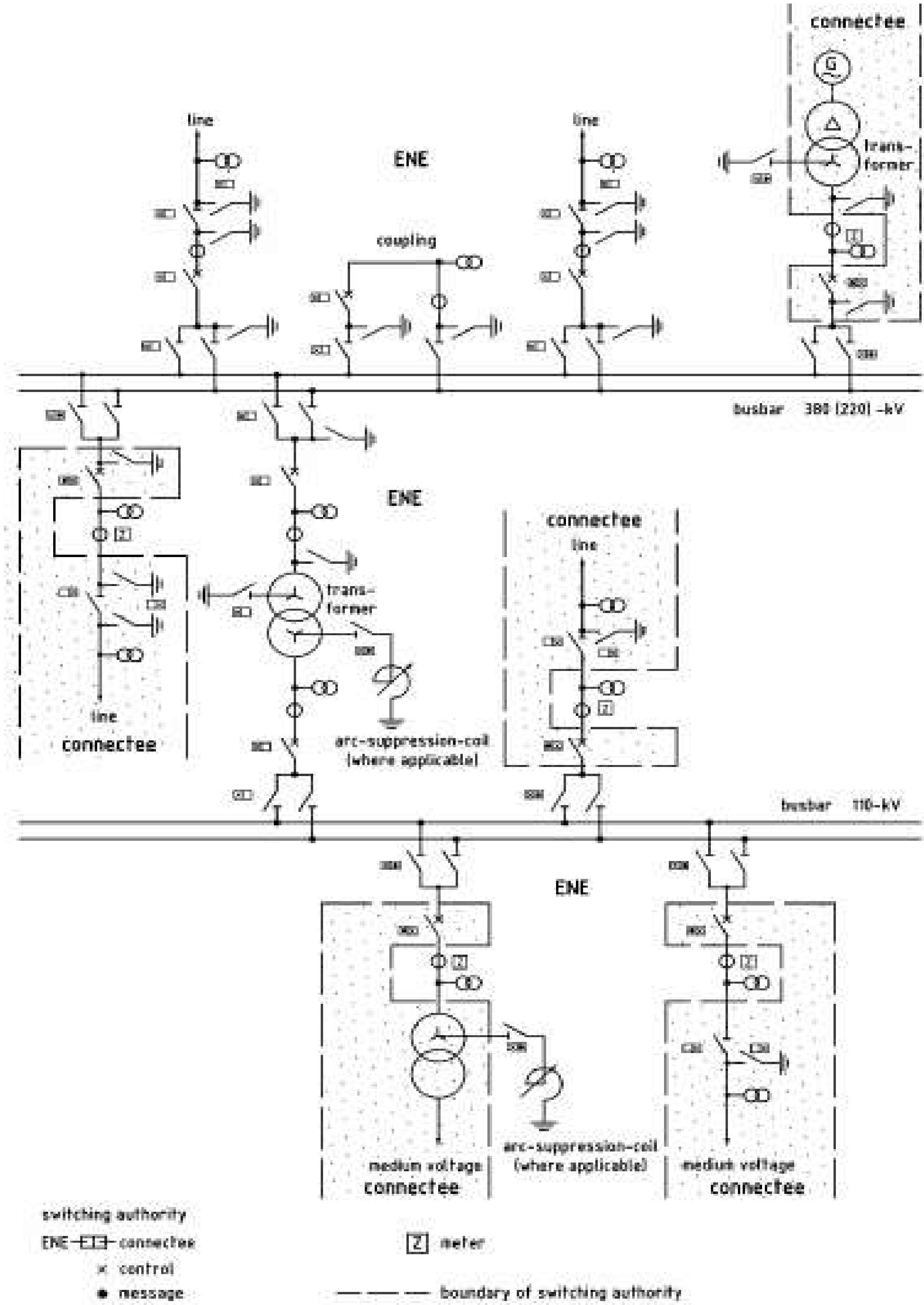



Figure 3 NE - station.

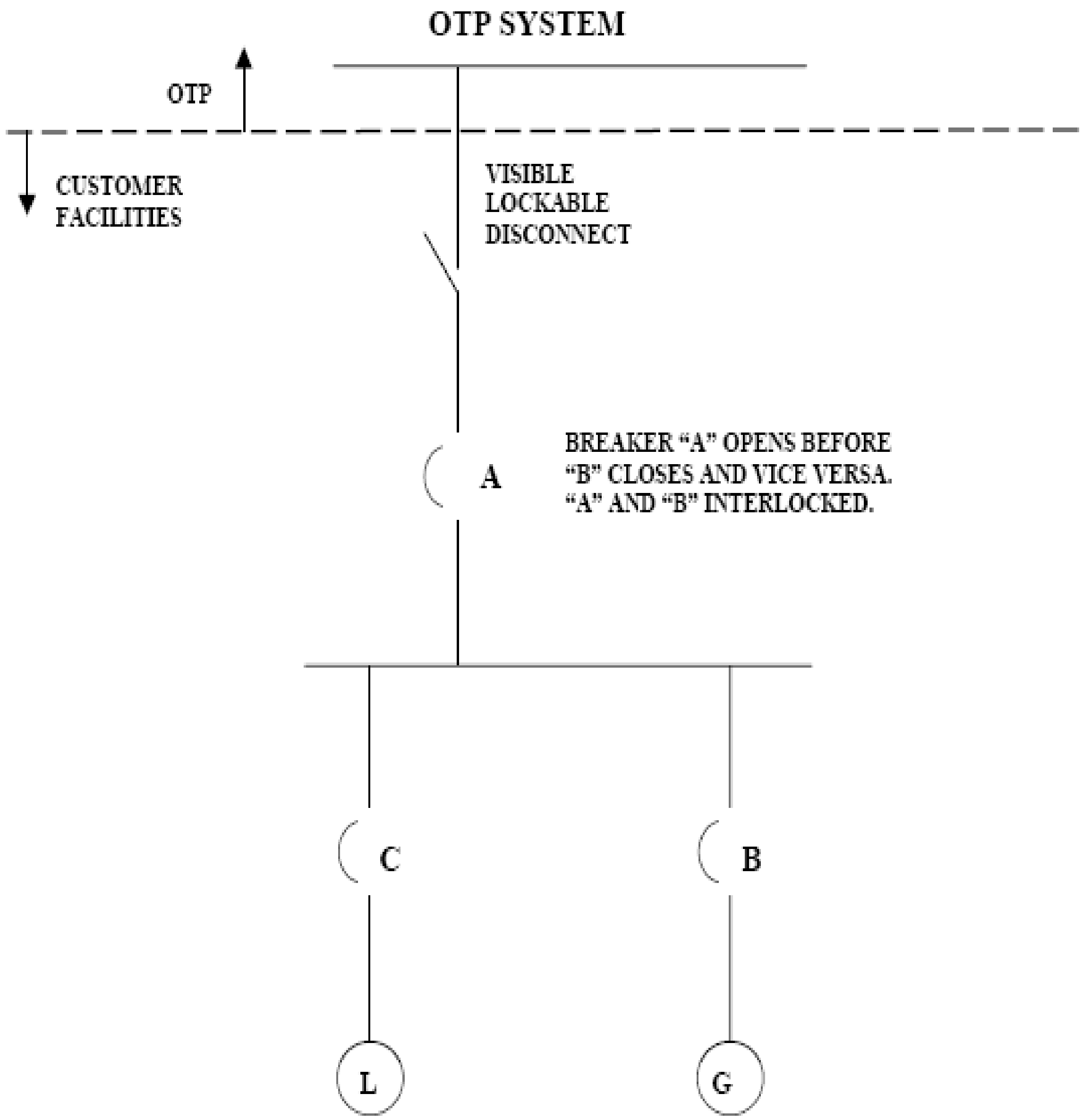



Figure 4 Typical break before make over for any installation.

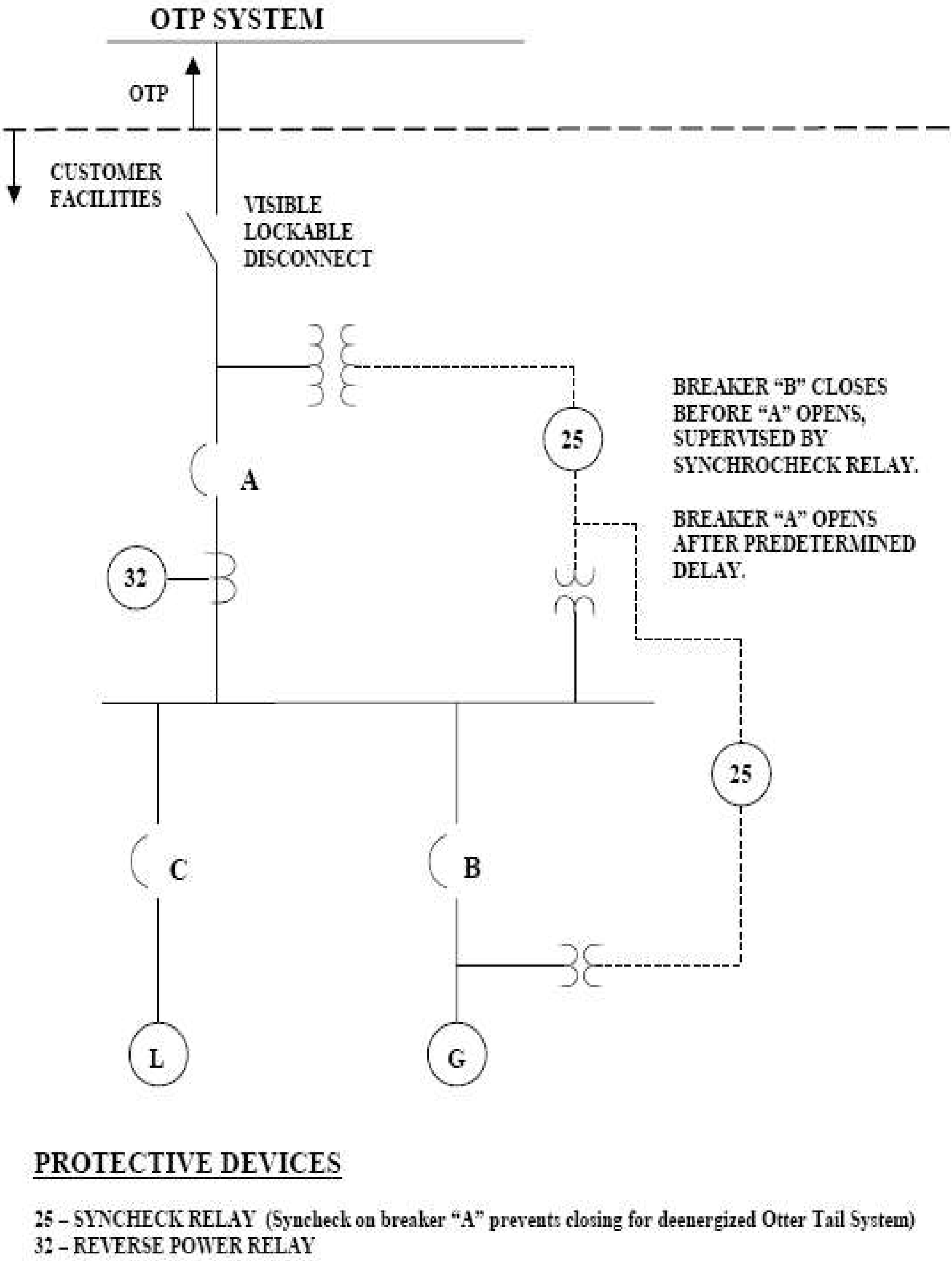
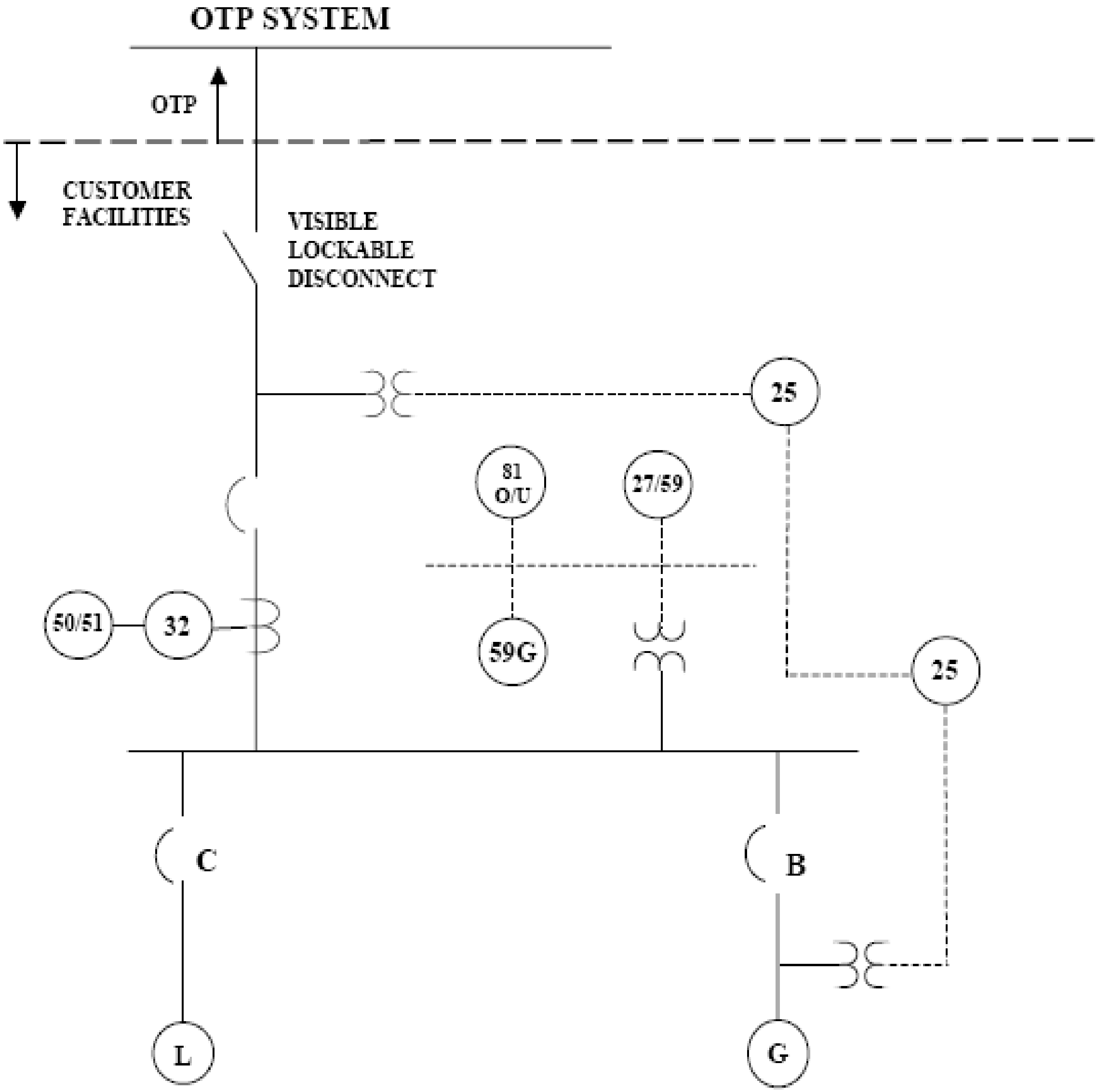



Figure 5 Typical make before break transition - Not intended for continuous operation.




**PROTECTIVE DEVICES**

| | | |
|---|---|---|
| 25 | – | SYNCHECK RELAY |
| 27/59 | – | OVER/UNDER VOLTAGE RELAY |
| 32 | – | REVERSE POWER RELAY |
| 50/51 | – | OVERCURRENT RELAYING |
| 59G | – | GROUND OVER VOLTAGE (FOR UNGROUNDED SYSTEMS) |
| 81 O/U | – | OVER/UNDER FREQUENCY RELAYING |

Figure 6 Typical continuous parallel operation for less than 5 MW.

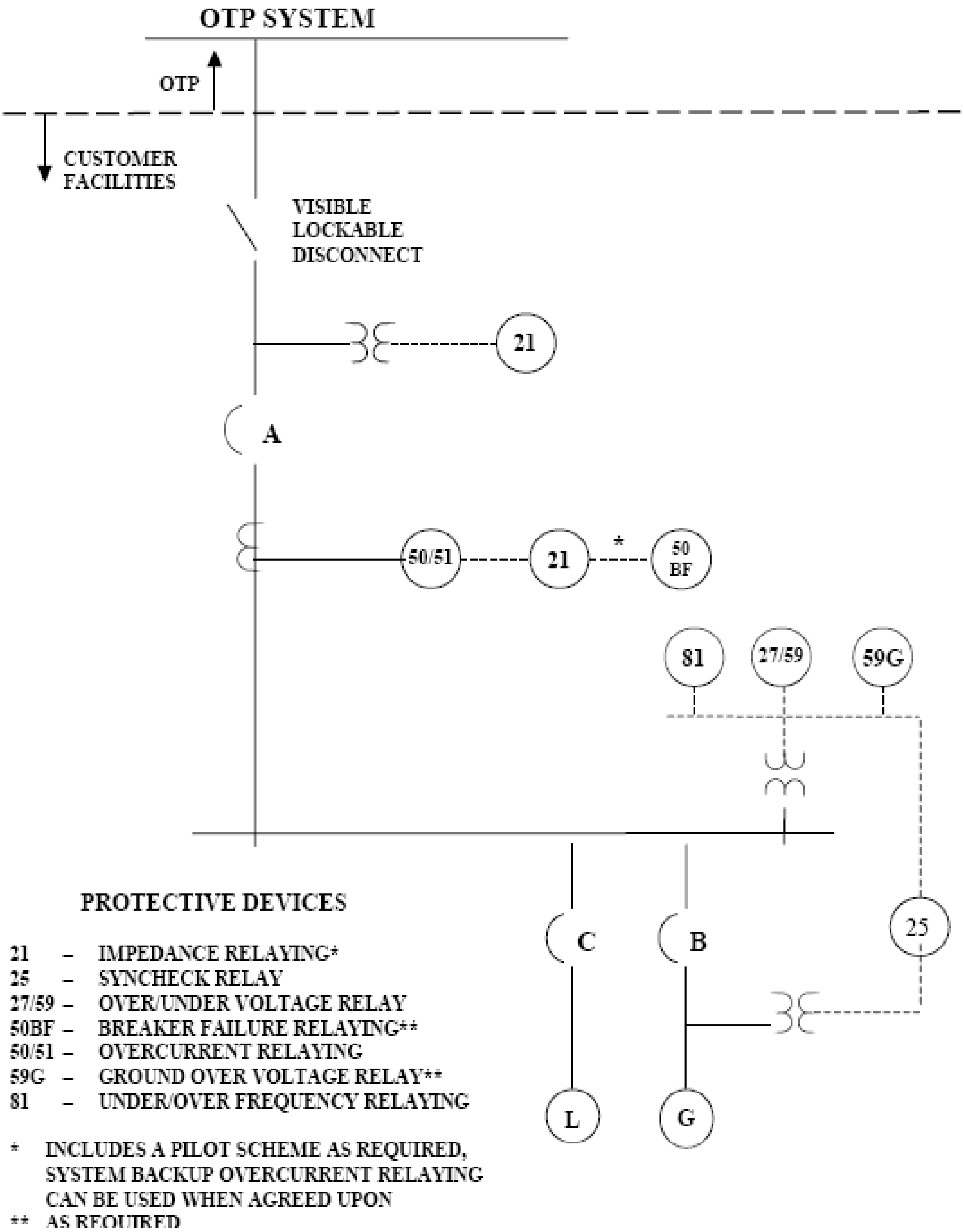



Figure 7 Typical continuous parallel operation, 5 MW and greater