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International Review of Fault Ride Through for Conventional Generators

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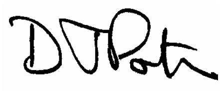

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EXECUTIVE SUMMARY

This report presents an international review of the fault ride through (FRT) requirements for conventional synchronous generators in terms of the minimum Grid Code (or technical rules where relevant) FRT requirements, their initial development and evolution over time and compliance assurance throughout the life of the synchronous generating plant. In addition, the changes to Grid Codes introduced in order to deal with a high penetration of non-synchronous generation, and in particular wind generation, have also been documented and reviewed. The report provides comment on the existing FRT requirements in Ireland and contrasts them with criteria in Great Britain, Spain, Germany, Denmark, USA (ERCOT), Western Australia and New Zealand. In doing so, the report also provides a high-level summary of the network characteristics and configurations adopted in these countries.

The review was based on publicly available information such as grid codes and technical rules and responses to a specially designed questionnaire that was sent to KEMA's contacts in the above mentioned countries in order to capture a more in-depth knowledge of the historical developments and compliance assurance processes.

A summary of the main findings from this international review follows:

- All transmission system operators reviewed have (or are considering introduction of) requirements that specify the response and behaviour of a synchronous generating plant connected at a transmission voltage level during grid faults that cause significant voltage disturbances. These requirements are normally set out in the national Grid Codes, standards or technical rules and apply at the high voltage side of the generator transformer (normally the point of common coupling) regardless of local conditions and irrespective of the pre-fault operating conditions.

- In the majority of countries studied these requirements are nowadays defined by voltage and time duration profiles that set limits for which a generator must ride through grid faults without disconnection, the fault ride through capability. The only exceptions are USA (ERCOT) where such requirements are not specified for synchronous generating units and New Zealand where they are currently under development.

- The existing voltage duration curves for fault conditions differ between the countries in terms of the severity of voltage drop considered during the fault, fault duration and voltage recovery during and after the fault. Even though these differences appear to reflect the different characteristics of the power systems used in these countries, it is not always clear from the information reviewed how these requirements were initially established, i.e. what analysis and assumptions underlay their derivation at the time. Western Power, Australia, was the only TSO to declare that the duration figure was derived from the worst case back-up protection clearing time on the 330kV network, plus a 30ms margin.

- It should be noted from the Great Britain perspective in particular that minimum planning requirements in relation to generator behaviour and overall system stability under the most severe grid fault conditions have been in existence since the mid 1970s. Following privatisation of the electricity supply industry in 1990, the planning criteria relating to the generation connection requirements were largely incorporated into the National Electricity Transmission System Security and Quality of Supply Standard with additional, more detailed, technical and design criteria and performance requirements for generating units defined in the Grid Code. The detailed fault ride through requirements for all generating units (synchronous and non-synchronous) were introduced into the GB Grid Code in June 2005.

- Increasing deployment of new non-synchronous generation technologies, especially large volumes of wind generation, has led to recent amendments and/or changes to the grid codes to introduce and / or clearly differentiate between the FRT requirements for synchronous and non-synchronous generating plant. It is interesting to note that in Australia and Great Britain non-synchronous generating units are required to have the same FRT capability as conventional generation whilst in the USA (ERCOT) specific FRT capability is required only from non-synchronous generating units. In all cases, the FRT requirement for non-synchronous generating plant has become a necessity in order to ensure system stability and security of supply and constitutes an integral part of all national Grid codes or technical rules.

The reviewed Grid Codes and technical rules provide relatively good insight into the compliance process in terms of the data and evidence of compliance that is expected to be submitted by the generator at the connection application and commissioning stages. In some countries (e.g. Great Britain, Australia) there are additional TSO guidance documents that provide detail on the overall compliance process including roles and responsibilities, technical studies and testing required to demonstrate compliance with Grid Code conditions and the process to be followed in the event of generator non-compliance. The technical rules of Western Power in Australia is the only document that specifically states the need for ongoing verification of detailed technical requirements. However, there seems to be no well-documented and specific procedures for assessing and enforcing compliance of synchronous generating units with FRT requirements, beyond generator confirmation statements.

1 INTRODUCTION

1.1 Background

Generating plants are normally expected to remain connected at system voltages within a defined voltage range and not have a detrimental effect on the ability of the System Operator to maintain system voltage within that range. This includes remaining in service not only under normal operating conditions and following faults but also during voltage and frequency excursions associated with system short circuit faults.

The occurrence and removal of short circuit faults by protection systems will often result in a momentary voltage dip experienced across the entire power system. A long, persistent, severe fault or the inability for generation to ride through a fault could result in the disconnection of large amounts of generation and possibly system collapse. The fault ride through (FRT) ability of generation to remain connected through disturbances on the power system is therefore critical to power system security. The capability of generation to remain connected to the power system during and following system faults depends heavily on the generator technology, design and control characteristics and short circuit levels. Other factors that are of importance are system characteristics, protection operation and protection fault clearance times. In order to be capable to remain in service in the event of a fault and return quickly to the pre-fault output after fault clearance, certain generating technologies may require additional dynamic voltage control (inbuilt or external).

In general, fault ride through requirements are defined by the voltage and time duration profiles that set out requirements of a generator to ride through grid faults without disconnection. For illustration purposes an example profile is shown in Figure 1.

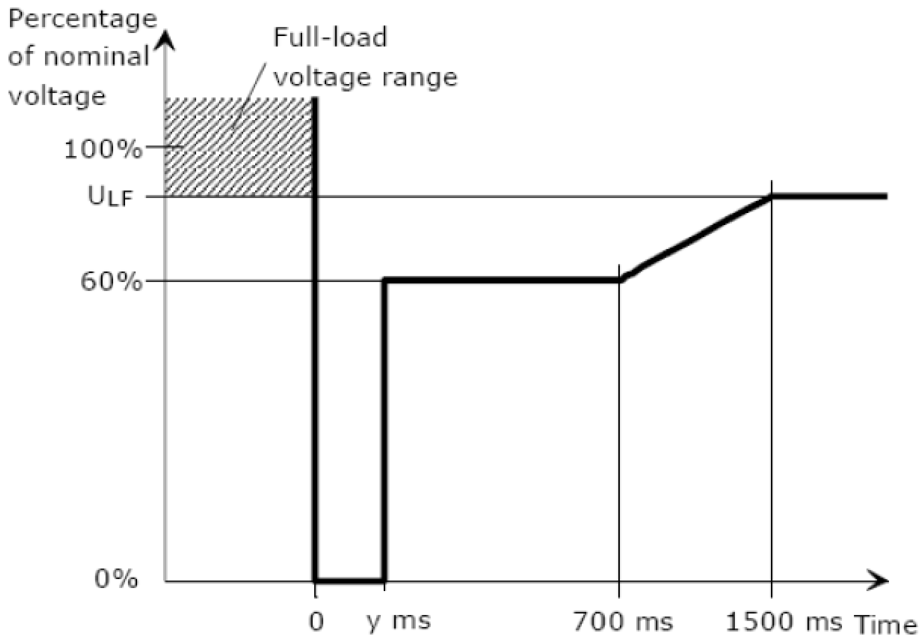

Figure 1. Voltage duration curve during grid fault

Each point on the profile (i.e. the heavy black line) represents a voltage level and an associated time duration which a connected generating unit must withstand or ride through. It is worth noting that the profile shown in Figure 1 is an overall envelope intended to encompass a number of differing voltage depressions and associated durations.

In addition, some profile curves are accompanied with requirements related to generator contribution to voltage stabilisation and system recovery during and after the fault. Rapid recovery of active power following restoration of voltage is of particular importance.

1.2 Project Overview

EirGrid is reviewing the conventional generation unit connection capability stated in the Irish Grid Code under section CC.7.3.1.1(h) which requires that

> Each **Generation Unit,** shall, as a minimum, have the following capability:
> remain synchronised during and following **Voltage** dips at the **HV** terminals of the **Generator Transformer** of 95% of nominal **Voltage** (5% retained) for duration 0.2 seconds and **Voltage** dips of 50% of nominal **Voltage** (i.e. 50%retained) for duration of 0.6 seconds. Following the fault clearance the **Generation Unit** should return to

pre-fault conditions subject to its normal **Governor Control System** and **Automatic Voltage Regulator** response.

EirGrid commissioned this study to review other international Grid Codes to ascertain the different approaches to the development of FRT requirements in other transmission networks. The study incorporates the following aspects:

- How the minimum standard was established i.e. what are the operating characteristics of the particular transmission network that led to the particular definition of FRT; has the value been changed and if so why;
- Voltage levels and length of lines of comparison network;
- Establish the differences, if any, in FRT requirements for interconnected systems and island networks;
- How other Grid Codes propose to deal with a high penetration of asynchronous generation expected through the proliferation of wind turbine generating systems;
- How other countries assess FRT for connection offers, at commissioning and for the lifetime of the Generation Unit;
- Have other countries changed FRT requirements because of increased penetration of wind generation and why?

EirGrid wished to obtain an understanding of FRT requirements across a range of systems from island networks with low inertia and poor interconnection through to large well-interconnected continental power systems. On commencement of the project it was agreed that FRT requirements in the following seven countries would be investigated;

- Great Britain,
- Spain,
- Germany,
- Denmark,
- USA (ERCOT),
- Australia (Western Power), and

- New Zealand.

KEMA is a global company with offices in most of the selected countries and often good contacts within the local Transmission System Operator (TSO) company. Indeed, some KEMA colleagues contributing information to this project are ex-TSO employees. This degree of local knowledge proved particularly invaluable in obtaining the rationale and history behind many of the fault ride through requirements reviewed.

Whilst much of the information with respect to existing FRT requirements is available through public domain information such as grid codes and technical rules it was necessary to obtain more in-depth knowledge of the historical derivation and compliance assurance processes in particular from local contacts. This was achieved by requesting they respond to a questionnaire developed specifically for this purpose as shown in Appendix B.

The findings from the public domain information, questionnaire feedback and subsequent discussion with KEMA colleagues based in the selected countries form the basis of this review.

2 EXISTING FAULT RIDE THROUGH REQUIREMENTS IN IRELAND

2.1 Main power system characteristics

The power system in Ireland is an interconnected system with an installed capacity of 6.3 GW, total energy demand of approximately 2.6TWh per month and peak demand of approximately 4.95 GW. The transmission system, often referred to as “The National Grid”, is operated by EirGrid. It represents a meshed network of approximately 6,500km of high voltage (110kV, 220kV and 400kV) overhead lines and underground cables and over 100 substations as illustrated in Figure 2.1.

At the end of 2009 there was 1526 MW of renewable energy installed in Ireland. This figure is split between wind (1,260 MW), hydro (236 MW) and other small renewable energy sources (30 MW) and represents approximately 14% of electricity demand.

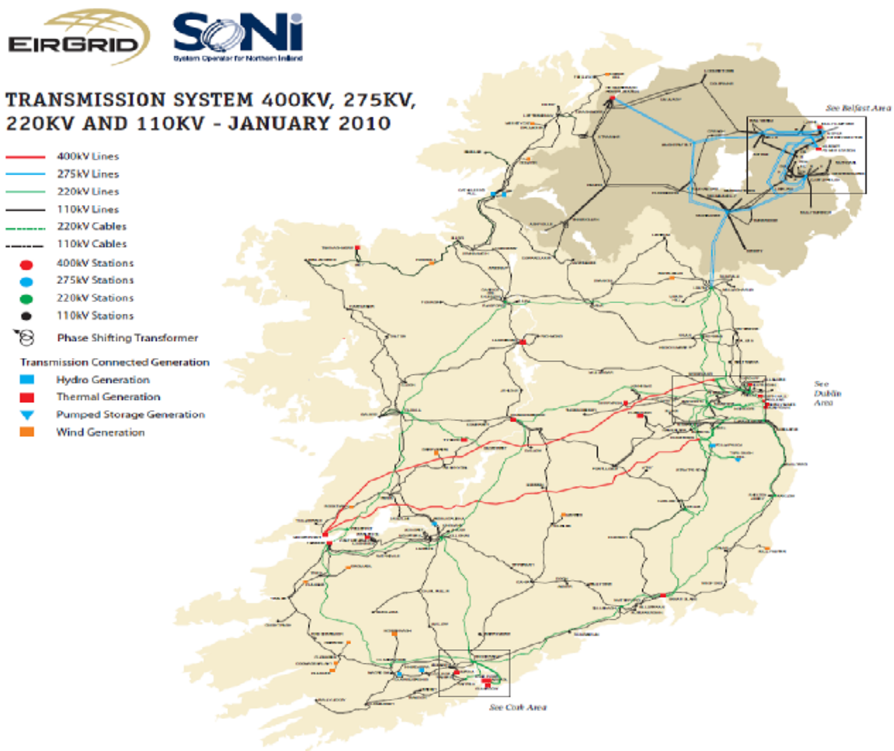

Figure 2.1 Transmission Network in Ireland, 2010
(http://www.eirgrid.com/transmission/transmissionsysteminformation)

2.2 Approach to FRT from historical perspective

In response to the European Directive 96/92/EC "1st Package", to ensure the establishment of technical rules of connection to the system, ESB National Grid (the predecessor organisation to EirGrid) produced an Interim Grid Protocol that was approved and issued in July 1997.

The Interim Grid Protocol addressed fault ride through in Section 1.4 Performance Standards Required from the Generator. This required a generator to ride through a three phase voltage dip of 100% of nominal voltage and 0.2 seconds duration and three phase voltage dips of 50% for a duration of 0.6 seconds.

In December 2000 Version 1.0 of the Grid Code was approved. The requirement for generator fault ride through capability was relaxed from 100% to 95% of nominal voltage for the duration of a three phase voltage dip for 0.2 seconds and clarification of the retained voltages added.

Further development of the FRT requirement of generators incorporated the need to remain synchronized during the fault recovery period as well as the fault clearance period. This development appeared in Version 3.1 of the Grid Code issued in May 2008 and remains unchanged in the current Grid Code Version 3.4.

2.3 Existing FRT requirements

The current version of the Grid Code, section CC.7.3 of EirGrid Grid Code Version 3.4 of October 16th 2009, provides specific design and performance standards for Connection Conditions related to synchronous generators with a registered capacity greater than 2MW.

In particular, the capability for fault ride through is stated in clause CC.7.3.1.1;

Each Generation Unit, shall, as a minimum, have the following capabilities:

(h) remain synchronised during and following **Voltage** dips at the **HV** terminals of the **Generator Transformer** [1]of 95% of nominal **Voltage** (5% retained) for duration 0.2 seconds and **Voltage** dips of 50% of nominal **Voltage** (i.e. 50% retained) for duration of

[1] A transformer that transforms the generation unit voltage to the network voltage.

0.6 seconds. Following the fault clearance the **Generation Unit** should return to prefault conditions subject to its normal **Governor Control System** and **Automatic Voltage Regulator** response;

2.4 Treatment of non-synchronous generation

The Grid Code was originally developed to cater for the connection of synchronous generators to the system. As wind turbine generators have different characteristics to synchronous generators a new set of Grid Code provisions have been developed specifically for controllable Wind Farm Power Stations (WFPS) and were approved by the CER on 1 July 2004.

Fault ride through requirements for WFPS are detailed in Section WFPS1.4 of the Grid Code and require a controllable wind turbine generator (WTG) to remain connected during a voltage dip of 85% (15% retained) of nominal voltage for a duration of 625ms at the HV terminals of the grid connected transformer.[2]

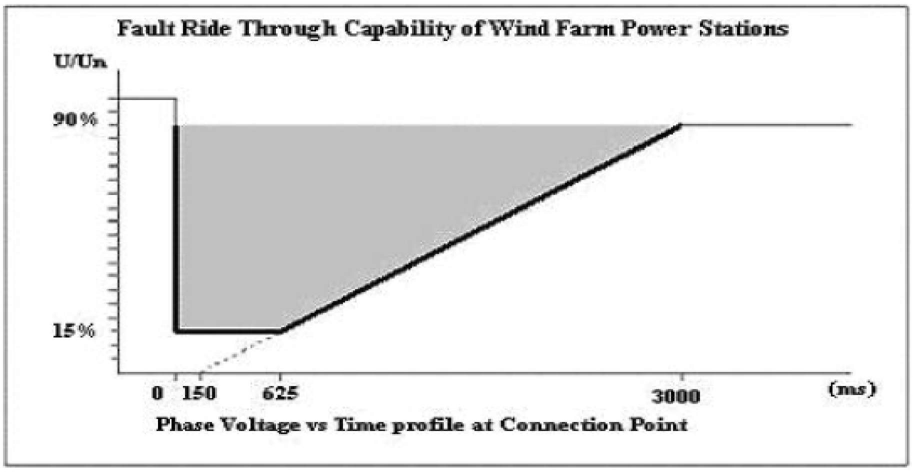

Figure 2.2 Fault ride through requirement of controllable WFPS

In addition to remaining connected to the network, the wind farm shall provide the following functions:

1. During the voltage dip the Wind Farm Power Station shall provide active power in proportion to retained voltage and maximise reactive current to the network without exceeding WTG limits. The maximisation of reactive current shall continue for at least

[2] A transformer directly connected to the transmission system.

600ms or until the voltage recovers to within the normal operating range of the transmission system, whichever is the sooner.

2. The Wind Farm Power Station should provide at least 90 % of its maximum available active power as quickly as the technology allows and in any event within 1 second of the transmission system voltage recovering to the normal operating range.

In addition to the requirements above, the TSO reserves the right to require a more enhanced FRT capability, or refuse connection to the network, for system security reasons.

3 INTERNATIONAL REVIEW OF FAULT RIDE THROUGH REQUIREMENTS

This section presents the findings from each of the selected countries with respect to FRT requirements, addressing the key topic areas of;

- Main power system characteristics,
- Approach to FRT from historical perspective,
- Existing FRT requirements, and
- Compliance assurance.

The considerations in relation to non-synchronous generation are presented in Appendix A.

3.1 Great Britain

3.1.1 Main power system characteristics

The power system in Great Britain is an interconnected system with an installed capacity of about 74GW, total energy demand of approximately 350TWh and peak demand of approximately 58GW. The system is made up of 167 large power stations[3], the 400kV and 275kV transmission system (and 132kV transmission system in Scotland) and 14 distribution systems.

The mix of fuels used to generate electricity has been changing over the years with the decline of coal and oil and the rise of gas and wind. At the moment, there is approximately 10.9GW of nuclear power plants, 22.7GW of coal power plants, 34GW of gas and oil power plants, 3.9GW of hydro power stations and 2.8GW of wind farms[4]. The aggregate power

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[3] The current Grid Code classifies all Power Stations based on their Registered Capacity (RC), as follows:
England & Wales (NGET Area) - Large ≥ 100MW, Medium ≥ 50MW, Small < 50MW.
South of Scotland (SPT Area) - Large ≥ 30MW, Small < 30MW.
North of Scotland (SHETL Area) - Large ≥ 10MW, Small < 10MW.

[4] Seven Year Statement 2010, National Grid. (http://www.nationalgrid.com/uk/Electricity/SYS/current)

station capacity is expected to rise to approximately 109GW by 2016/17 primarily due to the increase in CCGT and wind generation.

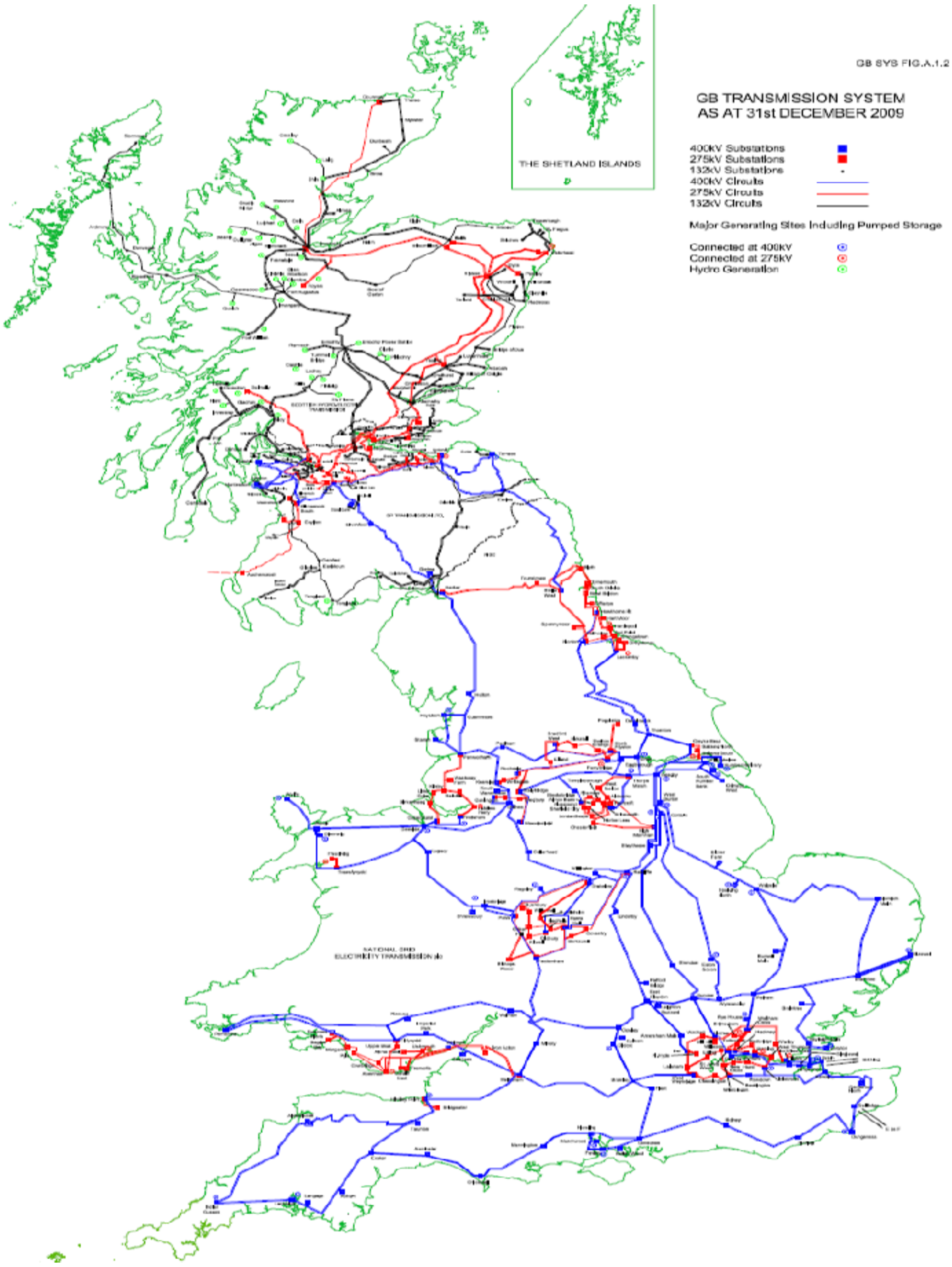

Figure 3.1.1: GB Transmission System (Ref: 2010 Seven Year Statement http://www.nationalgrid.com/uk/Electricity/SYS/current/)

The existing national electricity transmission system is depicted in Figure 3.1.1 with the 400kV system shown in blue, the 275kV system in red and the 132kV system in black. (Note: 132kV & 66kV are assumed to be supply voltages in England & Wales, but not in Scotland.)

There are approximately 22,600km of overhead lines and 1,230km of underground cables (including the HVDC link to France)[5].

The majority of large power stations are directly connected to the national electricity transmission system. However, several large power stations are embedded within the lower voltage distribution networks. Medium and small power stations are currently all embedded within the distribution networks.

There are three transmission licensee areas - Scottish Power Transmission (SPT) Area, Scottish Hydro Electric Transmission Ltd (SHETL) Area and National Grid Electricity Transmission (NGET) Area. In the NGET Area, National Grid is the Transmission Owner and System Operator. It is also the System Operator for SPT Area and SHETL Area. Scottish Power is the Transmission Owner in SPT Area and Scottish and Southern Electricity is the Transmission Owner in SHETL Area. In the case of off-shore installations NGET is the System Operator. National Grid also operates electricity interconnectors between England and Scotland (capacity 2.2GW) and jointly operates the HVDC interconnectors with France (capacity 2.2GW) and Northern Ireland (capacity 0.5GW). The third external interconnector with the Netherlands (capacity 1GW) is expected to be in operation by the end of 2010.

3.1.2 Approach to FRT from historical perspective

There were no specific generator Fault Ride Through (FRT) requirements prior to their introduction into the GB Grid Code in June 2005[6]. Instead, the required behaviour of generators was determined by overall transmission system stability requirements for which generator behaviour and appropriate parameters were crucial.

Under the CEGB (i.e. prior to privatisation of the electricity supply industry in 1990) security of supply, incorporating transient stability criteria, was specified in a number of documents; these are as follows:

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[5] The following figures are taken from the 2009 seven-year statement (SYS):
Overhead Lines: 400 kV -11,634 km; 275 kV - 5,766 km and 132 kV (& below) - 5,254 km.
Underground Cables: 400kV -195km; 275kV - 498km and 132kV & below - 216km; DC (Channel Link) - 327km.

[6] http://www.nationalgrid.com/NR/rdonlyres/D4943264-3CFD-40D4-A786-EEFE6FF57AE2/1411/I3R10upd.pdf

- CEGB Standard. Planning Memorandum PLM-SP-1. Planning Standard of Security for the Connection of Generating Stations to the System. September 1975.
- CEGB Standard. Planning Memorandum PLM-ST-4. CEGB Criteria for System Transient – Stability Studies (Supergrid System). September 1975.
- CEGB Standard. Operational Memorandum No. 3. Operational standards of security of supply. November 1989.

There are other standards but these are not related to transient stability and are not discussed here.

3.1.2.1 CEGB Standards and Practice

CEGB Standard. Planning Memorandum PLM-SP-1. Planning Standard of Security for the Connection of Generating Stations to the System. September 1975.
The purpose of the standard was to provide security of generation connection and as such there is no mention of stability issues or required fault ride through.

CEGB Standard. Planning Memorandum PLM-ST-4. CEGB Criteria for System Transient – Stability Studies (Supergrid System). September 1975.
This standard defined the fault outages for which the transmission system and generators had to remain transiently stable. It was noted that the system is subjected in practice to a wide range of faults and in general, the location and fault type cannot be predicted. The stability of generators was, therefore, to be assessed for the most severe fault type to which they could be subjected, i.e. a three phase fault.

Stability would normally be assessed on the basis of the slowest combination of main protection and signalling equipment and circuit breaker operating times. The fault clearance times would be inclusive of protection relays, signalling, trip relays, and circuit breaker operating times. Where equipment performance had not yet been specified, nominal operating times were to be used as specified in PLM-ST-1 (Planning Memorandum. Fault Clearance Times for System Studies). Within PLM-ST-4, PLM-ST-1 is noted as being in preparation. No record of the latter document was found and it is not known if it was ever produced.

CEGB Standard. Operational Memorandum No. 3. Operational standards of security of supply. November 1989.

This standard defined the fault outages that should not lead to unacceptable system conditions including high or low frequency, overloading of equipment, high or low voltages, or system or generator instability. No fault clearance times were defined.

Practice

In the 1970s and early 1980s system stability, following a fault, was assessed by carrying out transient stability studies using a nominal fault clearance time of 100ms to 120ms which represented the total time between fault inception and fault clearance and included protection operation and circuit breaker opening times. A simplified switching sequence was used which represented fault inception, followed by fault clearance and line switch out (as a single action) at the fault clearance time. By the late 1980s, increased computer program sophistication allowed detailed fault clearance sequences to be modelled and these included fault inception, circuit breaker clearance at the faulted end of the circuit followed by fault clearance at the remote end of the faulted circuit. These times were determined by the protection characteristics individually for each circuit that was to be studied. The times used were those for the faster operation of either first main or second main protection. There was considerable debate over whether the faster or slower of the two main protection times should be used, but it was decided that to utilise the slower time would add a further contingency to the fault sequence which could not be justified. The faster operation was normally that of first main protection, but not always.

The introduction of three and a half cycle breakers enabled fault clearance times of 80ms to be achieved at the close up ends of faulted circuits with 120ms at the remote end due to protection operation and signalling times. These became normally accepted times for study work.

Assessment of the transmission system and its development was undertaken by carrying out transient stability studies on those parts of the system that were considered vulnerable. The results of these studies were contained in CEGB confidential reports that were not made available in the public domain.

In addition, the CEGB maintained a detailed database of all circuit, generator, and generator controller parameters which allowed accurate study work to be undertaken. The issue of compliance did not arise as all data was under control of the CEGB, although some system tests were undertaken to verify study results. The database was discontinued following privatisation, as National Grid was no longer the owner of generation, although the Grid Code then (and still does) required generators to provide appropriate parameter information to allow National Grid to continue to carry out study work to assess the security of the transmission system.

3.1.2.2 National Grid Standards and Practice

Following privatisation of the CEGB in 1990, which created the National Grid Company (NGC), responsible for the transmission system, and a number of generating companies, these standards continued to be used by NGC until November 2000, when, after a lengthy public consultation process, NGC published its Transmission System Security and Quality of Supply Standard as Issue 1. The Security and Quality of Supply standard (SQSS) has continued to be developed with the latest document published as the National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS) in June 2009.

Issue 1 of the national SQSS contained both planning and operational standards and was largely based on the old CEGB memoranda, although they were more logically codified and the planning and operation standards were made more consistent both in style and content. Nevertheless, the secured contingencies are similar (although not identical) to those of the CEGB planning and operational memoranda. Both planning and operational standards included the criteria that required, with an intact network and under prevailing conditions, following a fault outage of any double circuit overhead line, section of busbar, or a single outage of other transmission equipment there shall not be any system instability.

These planning and operational requirements remain within the current NETS SQSS, although the standard has been enhanced to include both onshore and offshore transmission. However, no version of this standard has included specification on fault clearance times to be used in assessing stability of generation and the transmission system.

Following privatisation, the CEGB practice of using actual fault clearance times for each study was continued. Compliance was not an issue as generator and controller parameters were submitted by the generators in accordance with the prevailing Grid Code(s)[7] and used in system stability studies undertaken by NGC for planning purposes. Verification of these parameters was undertaken by NGC during the commissioning of new generation and, indeed, generators were advised by NGC of Power System Stabiliser parameters that would

[7] The England and Wales Grid Code and the Scottish Grid Code. The E&W Grid Code was introduced in March 1990. In March 2001 the New Electricity Trading Arrangements were introduced and Issue 2 of the Grid Code was issued. At British Electricity Trading and Transmission Arrangements (BETTA) Go-Active on 1 September 2004 Issue 3 of the Grid Code was introduced.

be optimum for transmission system performance. No system tests to verify transmission system stability performance have been undertaken since privatisation.

In the initial versions of the England and Wales (E&W) Grid Code and the Scottish Grid Code post-privatisation, there were no explicit connection requirements on generators performance during grid faults; only the minimum protection fault clearance times were specified as 80ms at 400kV, 100ms at 275kV, and 120ms at 132kV in E&W and 140ms at 132kV in Scotland. These fault clearance times were included in the Supplemental Agreements with the generators. The E&W Grid Code minimum fault clearance times of 80ms, 100ms and 120ms have been retained in the combined Great Britain Grid Code which came into effect with BETTA Go-Active in September 2004 although the Supplemental Agreements are now Bilateral Agreements.

The specific FRT Grid Code requirements for all generating plant connected to the national transmission system were introduced in June 2005.

3.1.3 Existing FRT requirements

The FRT requirements are covered in the Connection Conditions (CC) section of the national Grid Code, Issue 4 Revision 4 – 18 October 2010[8].

Section Connection Conditions CC.6.3.15 sets out the fault ride through requirements on conventional generating units, Power Park Modules and DC converters.

The FRT requirements for all onshore generating units are defined for

(a) short circuit faults at a supergrid voltage[9] up to 140 ms; and

(b) supergrid voltage dips greater than 140 ms in duration.

(a) Short circuit faults at supergrid voltage up to 140 ms

For a close up solid 3-phase, or any unbalanced, short circuit fault at supergrid voltage each generator unit shall remain transiently stable and connected to the system without tripping for

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[8] http://www.nationalgrid.com/NR/rdonlyres/67374C36-1635-42E8-A2B8-B7B8B9AF2408/43566/Z_CompleteGridCode_I4R4.pdf

[9] The supergrid voltage is defined as the 400 and 275 kV transmission system

a total fault clearance time of up to 140 ms. The duration of zero voltage during a solid three-phase or unbalanced earthed fault is dependent on local protection and circuit breaker operating times. The specific duration and the fault clearance times will be specified in the bilateral connection agreement between the transmission owner and the generator. Following fault clearance, recovery of the supergrid voltage to 90% may take longer than 140ms.

Two examples of voltage recovery for short circuit faults cleared within 140ms are illustrated in Figures 3.1.2 and 3.1.3.

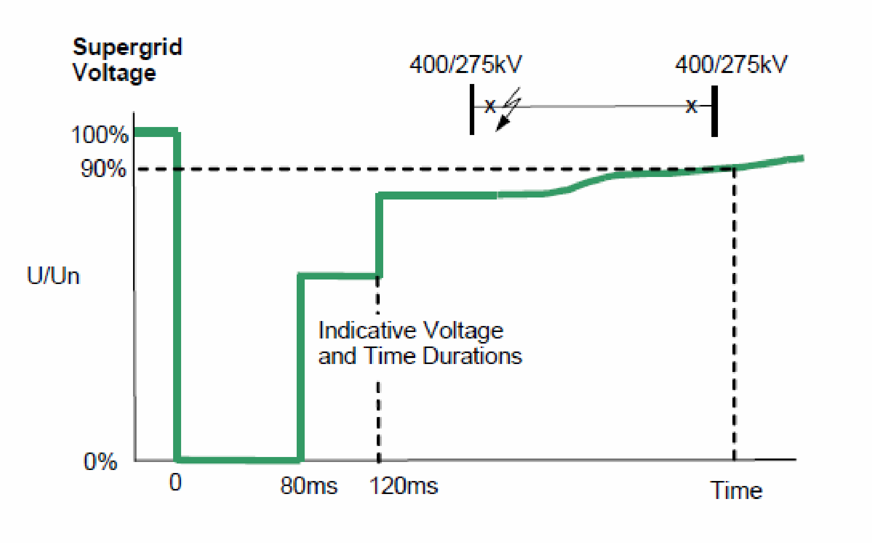

Figure 3.1.2. Fault cleared within 140ms by two CBs

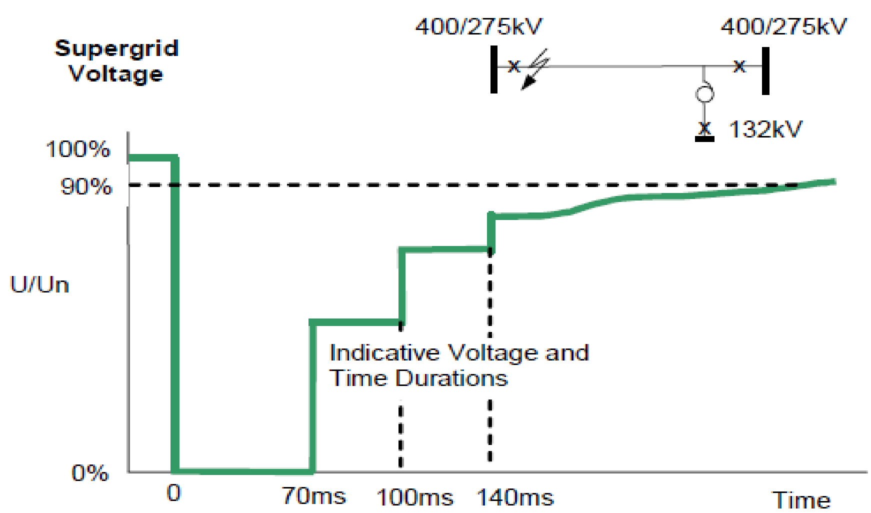

Figure 3.1.3. Fault cleared within 140ms by three CBs

Active power output should be restored to at least 90% of the level available immediately before the fault:

- following clearance of the fault and within 0.5s of the restoration of the voltage to minimum nominal voltage level at the grid entry point[10]; or
- within 0.5s of restoration of the voltage at the user system entry point[11] to 90% of nominal or greater for an embedded[12] generating unit.

Once the active power output has been restored to the required level, active power oscillation should be acceptable provided that:

- The total active energy delivered during the period of the oscillations is at least that which would have been delivered if the active power was constant.
- The oscillations are adequately damped.

During the period of the fault for which the voltage at the grid entry point is outside the steady state allowed voltage limits, each generating unit shall generate maximum reactive current without exceeding the transient rating limit of the generating unit.

The allowed voltage variations are as follows (CC.6.1.4):

- At 400kV:
  - normally within ±5% of the nominal value;
  - the minimum voltage is -10%;
  - the maximum voltage is +10%, but voltages between +5% and +10% should not last longer than 15 minutes.
- At 275kV and 132kV, normally within ±10% of the nominal value.
- At voltages below 132kV, normally within ±6% of the nominal value.

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[10] Grid Entry Point. An onshore grid entry point is a point at which an Onshore Generating Unit a Onshore Power Park Module, as the case may be, which is directly connected to the Onshore Transmission System connects to the Onshore Transmission System.
[11] User System Entry Point is a point at which a Generating Unit, or a Power Park Module which is Embedded connects to the User System.
[12] Embedded means having a direct connection to a User System or the System of any other User to which Customers and/or Power Stations are connected, such connection being either a direct connection or a connection via a busbar of another User or of a Transmission Licensee (but with no other connection to the National Electricity Transmission System).

Under fault conditions, voltage may collapse transiently to zero at the point of fault until the fault is cleared.

NGET and a generator may agree greater or lesser variations in voltage to those set out above in relation to a particular connection site.

(b) Supergrid voltage dips greater than 140ms in duration

In addition to the requirements set under part (a), the following requirements apply to each generating unit installed on or after 1 April 2005:

For balanced supergrid voltage dips having durations greater than 140ms and up to 3 minutes the fault ride through requirement is defined by the voltage duration profile illustrated in Figure 3.1.4. That is, each generating unit is required to remain transiently stable and connected to the system without tripping for voltage dips and associated durations anywhere on or above the heavy black line shown in Figure 3.1.4.

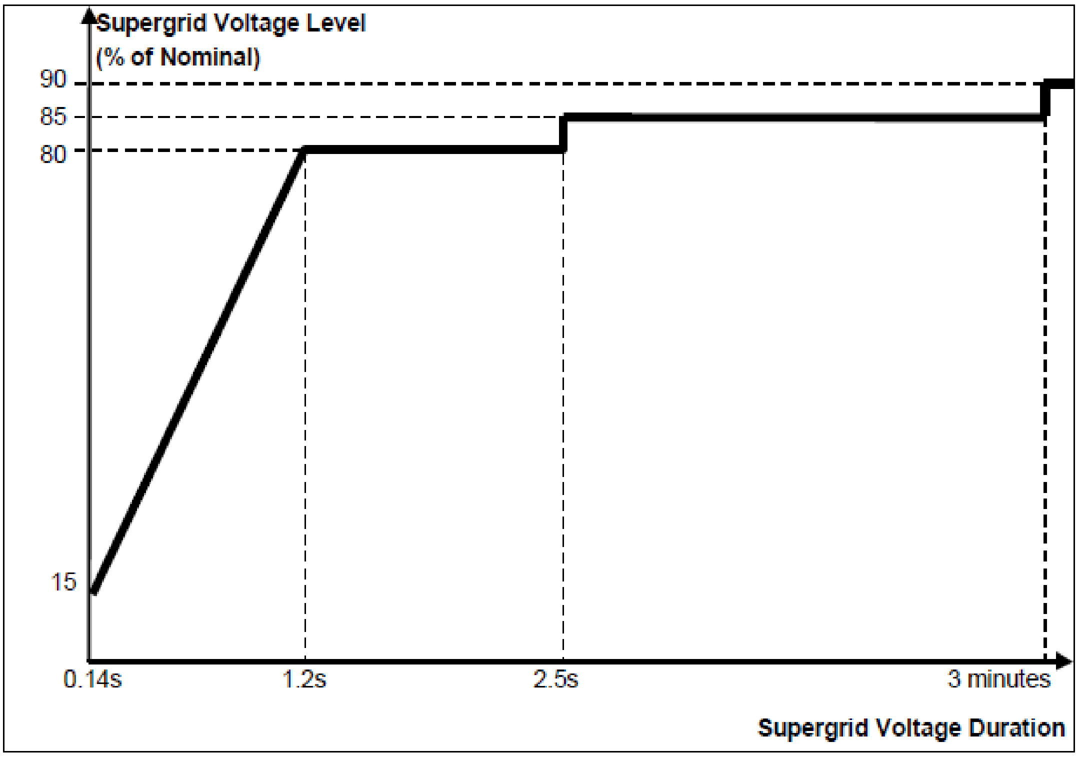

Figure 3.1.4. Voltage duration profile for voltage dips longer than 140ms

During supergrid voltage dips the unit should provide active power output at least in proportion to the retained balanced voltage at the grid entry point (or the voltage at the user system entry point if embedded).
Active power output following supergrid voltage dips should be restored to at least 90% of the pre-fault output:

- within 1s of restoration of the voltage at the grid entry point to minimum voltage levels; or
- within 1s of restoration of the voltage at the user system entry point to 90% of nominal or greater if embedded.

The only exception is a non-synchronous generating unit where there has been a reduction in the intermittent power source during the time range in Figure 3.1.4 that restricts the active power output.

Where the voltage at the grid entry point is outside the allowed voltage limits as described above, generator units should provide maximum reactive current without exceeding the transient rating limits of the unit.

These requirements apply to both synchronous and non-synchronous generating plant. However, there are certain exemptions that apply to non-synchronous generating plant only; for details, see Appendix A.1.

3.1.4 Compliance assurance

In order to synchronise and export power onto the electricity system, generators are required to achieve and maintain so called Operational Notification (ON). To achieve Operational Notification the generator must demonstrate compliance with the Grid Code and Bilateral Agreement (e.g. a site specific document agreed by National Grid and the Generator, which for technical reasons, may specify additional/alternative requirements). All compliance evidence, test results and associated data are to be compiled into a single report known as the User Data Library (UDL) (ex Connection Conditions Compliance Report (CCCR)).

Separate guidance notes have been written for conventional synchronous generation technologies[13] and power park modules[14] that provide an overview of the compliance

[13] Guidance Notes for Synchronous Generators, National Grid, September 2008.
[14] Guidance Notes for Power Park Developers, National Grid, September 2008.

process, associated milestones and lifetime compliance requirements. These documents also describe in greater detail the technical studies and testing required to demonstrate compliance with the connection conditions section of the Grid Code.

National Grid manages the Compliance Process for all transmission connected power stations and embedded large power stations. For embedded medium and small power stations the relevant Distribution Network Operator (DNO) is responsible for the compliance process. National Grid will normally identify the expected timescales for the various actions in compliance process and co-ordinate, witness and record any testing or monitoring required.

All generators are responsible for self certifying the compliance statements, with suitable supporting evidence, declaring that their equipment is compliant with the Grid Code and Bilateral Connection Agreement. To streamline the process National Grid provides a site specific compliance statement pro-forma to each new generation project, to be completed by the generator. In addition, National Grid provides a pro forma summary front sheet which should be used by the generator to highlight any non-compliance issues. Generators are requested to submit all data in requested formats for incorporation into National Grid's information management system and forwarding to the relevant Transmission Owner (TO) where necessary.

3.1.5.1 Connection, Energisation and Synchronisation Process

The commissioning process within National Grid is shown in Figure 3.1.5.

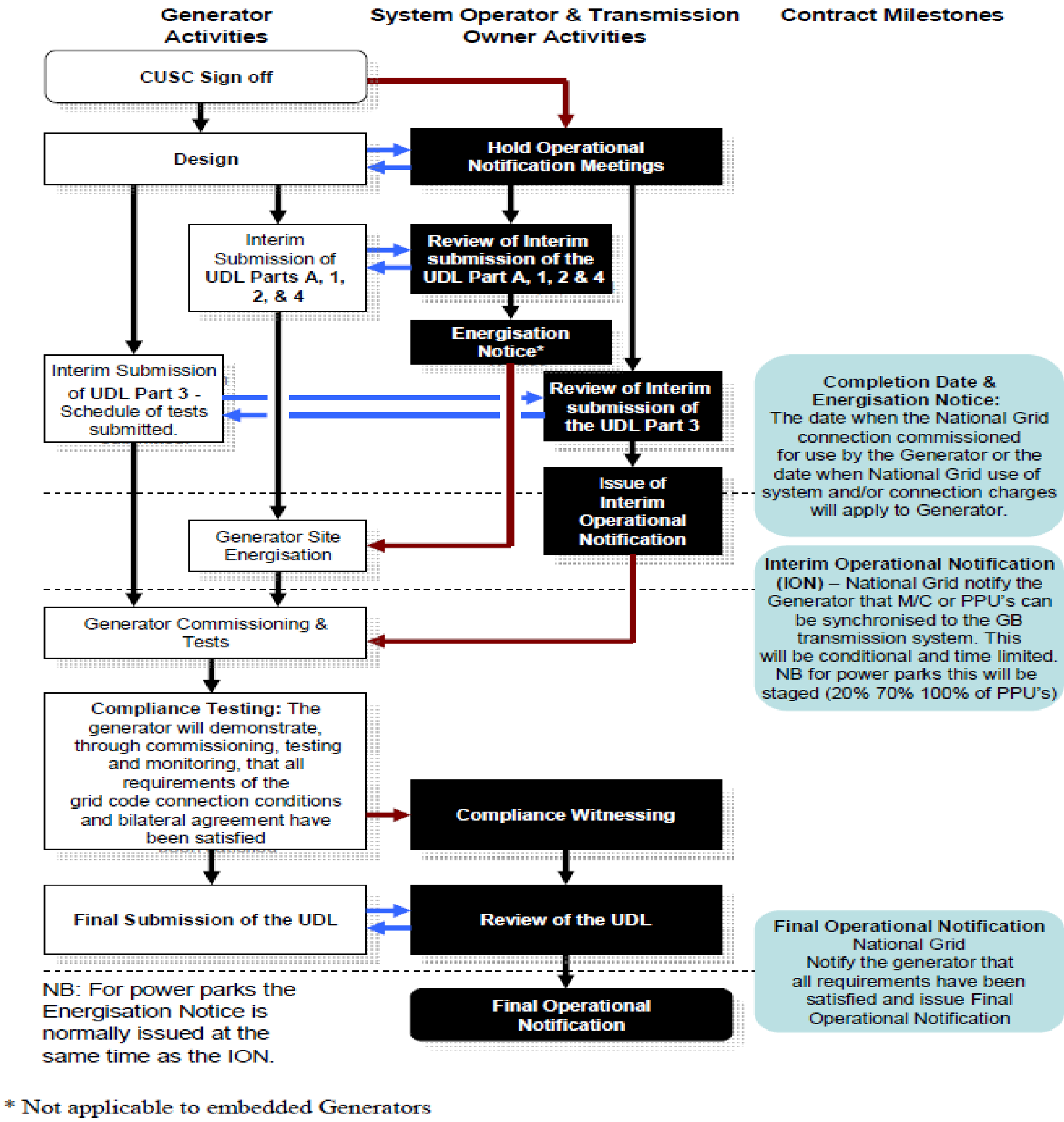

Figure 3.1.5. National Grid Compliance process
(http://www.nationalgrid.com/NR/rdonlyres/6C036707-27A4-4C43-AD8A-777487AAAFFF/28685/GuidanceNotesforPowerParkDevelopersIssue2September.pdf)

At synchronisation stage National Grid should have all parts of the UDL including self-certifying compliance statements with a pro forma summary front sheet highlighting any known or potential non compliance issues. The UDL will contain among other things, simulation studies demonstrating compliance and simulation studies predicting plant behaviour during compliance tests and compliance test programme. The plant data should include a verified model of the generator and its control systems in transfer function diagram format.

National Grid reviews all the endorsed data in the UDL and the accompanying self-certified compliance statements, and if satisfied, it will then consent to synchronisation. This consent is issued as an 'Interim Operational Notification' (ION) by National Grid. The ION will be time limited to cover the commissioning and compliance demonstration period and may include operational constraints. The ION will include a list of any outstanding issues which must be resolved through compliance testing or otherwise and within defined timescales before Final Operational Notification (FON) can be achieved.

3.1.5.2 Compliance with the FRT requirements

In order to demonstrate compliance with the Connection Condition CC 6.3.15 of the Grid Code, the synchronous generator is required to confirm / self-certify that

- the excitation system fitted to the generating unit complies with the requirements advised by National Grid, and
- generating unit protection will not cause the unit to trip for the voltage dips described by CC.6.3.15.

As there are no specific tests or simulation studies identified in the guidance notes for synchronous generators, it is not clear what evidence has to accompany the self-certification statement made by the generator in order to be able to verify that the FRT requirements have been met.

For details on a compliance process for a non-synchronous generating plant, see Appendix A.1.

3.1.5.3 Ongoing compliance

It is a requirement of the Grid Code that all generators submit standard and detailed planning data on an annual basis. National Grid will contact generators in calendar week 17 requesting an update of certain data schedules by the generator in calendar week 24.

It is not clear however whether and how is ongoing compliance with the FRT requirements checked and / or verified on an annual and/or ongoing basis.

3.1.5.4 Lifetime compliance

The lifetime compliance process ensures that all generating plant remains compliant throughout its lifetime as gradual degradation or replacement can result in a change of generator status.

After the issue of a FON National Grid will continue to monitor the plant performance and will discuss any concerns with the Generator as part of a normal and ongoing liaison process. This monitoring is particularly, but not exclusively, focussed on performance during frequency incidents and system fault events. In addition the generators should inform National Grid if their plant is about to become, or as soon as it becomes non-compliant through gradual degradation, or because the generator plans to replace or enhance existing plant. National Grid should be informed even if the modification or new plant will be Grid Code compliant. For example if a control system is replaced by a better one, it might fulfil all Grid Code requirements but the model previously submitted would have become invalid and therefore not fit for simulation studies.

Whilst the generator re-establishes compliance, the status of the plant, in terms of Operational Notification from National Grid, is shown in Figure 3.1.6.

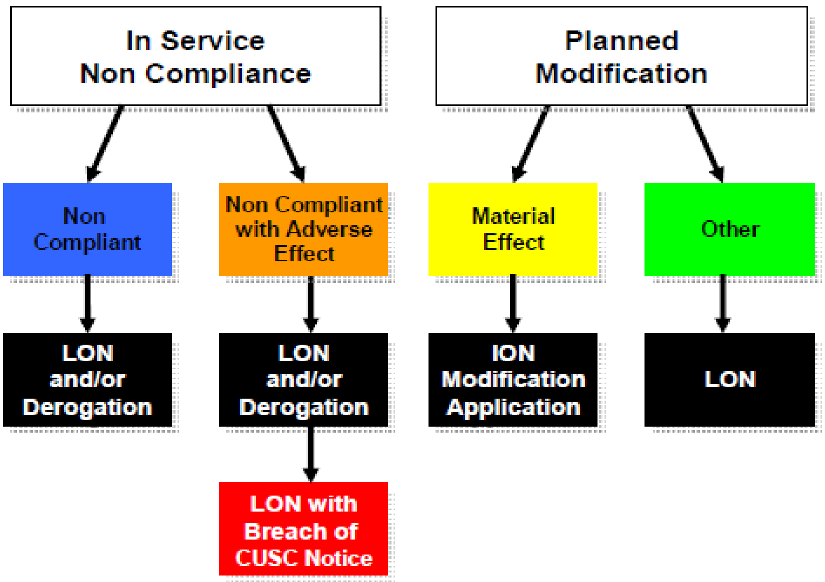

Figure 3.1.6: Generating Plant status whilst re-establishing compliance

In service non-compliance
The life time compliance process will be triggered, either as a result of an issue arising from National Grid's monitoring or as a result of a generator notifying National Grid of a non compliance. In notifying National Grid of a non compliance as soon as it arises, the generator should include details indicating the nature of the problem, any restriction arising from it and provide an indication as to when it will be rectified. The resulting outcome which includes issue of Limited Operational Notification (LON) and/or referral to Ofgem for a Time Limited Derogation is largely dependant on the significance of the non-compliance and the length of time the non compliance is predicted to or actually lasts for.

The LON, if issued, will include a schedule of outstanding compliance issues together with timescales for their resolution. National Grid will monitor the situation and identify and notify the generator of the tests and studies necessary to confirm that compliance with the Grid Code and Bilateral Agreement has been re-established. Regarding costs arising from non-compliance aspects, the principle that the party who has caused it pays will apply. If the generator claims the non-compliance is absolute and cannot be rectified economically the generator and National Grid will be required to request the corresponding lifetime derogation. Ofgem may issue a derogation including terms and conditions. Alternatively Ofgem may turn down the request. Requests to Ofgem for derogation can only be made by parties holding a Licence and only for Grid Code related issues.
It is worth noting that Non Compliance with the Bilateral Agreement but compliance with the Grid Code will not result in requests for derogation but other parts of the procedure will still apply.

In Service Non Compliance – Adverse Effect
Where the non compliance does have an adverse effect on National Grid or adversely affects other users of the system, the generator will be notified in writing as soon as possible seeking confirmation that the generator will take steps to restore compliance on an urgent basis. Failure to restore compliance may lead to notification of default and de-energisation in accordance with National Grid's rights under the CUSC.

Planned Modification
The changes to plant and control systems which result in or have the potential for changing operational characteristics (including the submitted data and models) and / or a new model for the modified or new plant should be submitted to National Grid to evaluate whether the modified plant will be compliant and will not adversely affect the transmission system or other user's plant.

A LON will be issued if there is no material effect as a result of the changes or an ION if there is a material effect. The plant will be tested for compliance, where National Grid considers it necessary and assuming the tests indicate that the modified plant is compliant, a FON will be issued.

In situations where some plant/equipment is replaced with newer variants, which are required to and are capable of meeting the latest Grid Code requirements, but the overall performance remains limited to some previously agreed level by other plant not being replaced: National Grid will take a pragmatic view to the level of performance which needs to be achieved and demonstrated.

3.2 Spain

3.2.1 Main power system characteristics

Red Eléctrica de España (REE) owns and manages most of the 400kV and 220kV transmission network in Spain with the following high level characteristics[15]. The 400kV transmission network length totals some 18,015kms of which 55km are cable. The 220kV network length totals 16,978kms of which 186km is cable.

The Spanish transmission network also has approximately 6,900MW of interconnection capacity with other ENTSO-E members and Morocco;

- France 1,400MW,
- Portugal 3,400MW,
- Andorra 600MW, and
- Morocco 1,500MW.

Maximum demand in 2009 was 44.9GW with connected generation capacity totalling 94GW consisting of;

- Nuclear 7,716MW
- Coal 11,359MW
- Other thermal 32,824MW
- Wind 18,865MW
- Hydro 18,631MW
- Other renewable 4,702MW

[15] http://www.ree.es/ingles/sistema_electrico/pdf/infosis/sintesis_REE_2009_eng.pdf

3.2.2 Approach to FRT from historical perspective

Prior to 2005 there has been no requirement in the Spanish codes for conventional generation to satisfy a fault ride through capability. However, as the penetration of wind energy increased markedly in some regions the need to maintain wind capacity during network disturbances triggered a review of generator connection requirements.

The first Spanish grid code requirement to specify a FRT capability for generators was published in a Ministerial Order P.O. 12.2 "Instalaciones conectadas a la red de transporte: requisitos mínimos de diseño, equipamiento, funcionamiento y seguridad y puesta in servicio." on February 11th, 2005[16]. This document concerns the minimum requirements on design, equipment, operation, security and commissioning of all types of new generation. The new generator FRT capabilities were considered necessary in order to guarantee their safe integration and compliance with the safety criteria set out by the operating procedures regarding system security and stability. System stability is the main driver for the establishment of FRT requirements.

Specific FRT requirements result from transient stability studies performed by the Spanish transmission operator (REE) with the collaboration of the Portuguese transmission operator (REN) and the Wind Business Association technically supported by ABB Consulting. A winter power demand peak scenario and a summer off-peak demand scenario were considered. The events studied were three phase faults in the transmission network buses, clearing the fault after a period considering circuit breaker failure protection (250 ms).

3.2.3 Existing FRT requirements

The low voltage limits to satisfy the fault ride through requirements of P.O. 12.2 are shown in Figure 3.2.1.

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[16] http://www.ree.es/operacion/pdf/po/PO_resol_11feb2005.pdf

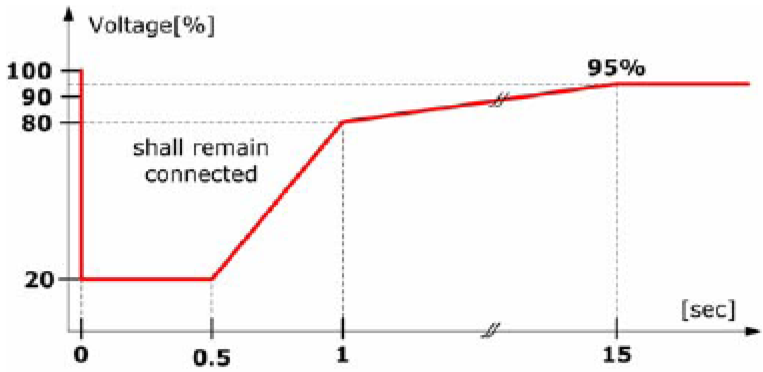


Figure 3.2.1: Fault ride through requirement of P.O.12.2 for conventional generators.

It is not known how a ride through duration of 500ms was determined in relation to the circuit breaker fail protection duration of 250ms.

The appendix on technical requirements in P.O.12.2 is currently under revision with a proposal to amend FRT capability to zero retained volts for a period of 150ms. This current revision consultation also proposes that the revised requirement shall also apply to non-synchronous generators. For more detail on the existing FRT requirements on non-synchronous generators, see Appendix A2.

3.2.4 **Compliance assurance**

Application Phase

The connection application process in the case of new conventional generators is detailed in P.O.12.2 which describes a two stage process;

1. request for access to the transmission network,
2. request for connection to the transmission network.

For stage 1, the generator must submit a request for access to a specific network location (node) and has to supply a variety of technical data about its generating plant from rated power to the PSS/E control block models for dynamic analysis. The annexes of REE P.O. 12.1 list all the necessary data for different generation technologies. After receiving the request for access accompanied by the generator data, REE has two months to provide a report stating the possibility of connection at the requested location from the perspective of system capacity. In the case of a positive conclusion, it is then possible to advance to Stage 2.

At stage 2, the generator must submit to REE the basic design of its installation, the construction program and a report showing that the installation fulfils all the technical requirements of P.O.12.2 proving that all the connection requirements are respected. These documents define protection requirements, grounding requirements, switchgear arrangements, fault ride through capability etc. The generator has one month to deliver these documents after he received a positive conclusion from Stage 1. In turn, REE has one month to provide a conclusion on the adequacy of documents presented by the generator.

System studies are performed by REE during Stage 2 from data supplied by the generator and comprise steady-state and dynamic assessments to verify that the operating requirements at the connection location, as per P.O.12.2 , are respected under all system conditions.

Commissioning Phase

Whilst additional technical and operational information and a test programme is submitted to REE by the generator prior to commissioning activities, no specific reference is made to testing fault ride through capability. If any non-compliances with P.O.12.2 are detected then the generator is not permitted to connect or commence commercial operation.

Ongoing Operation

No documented procedures for assessing ongoing compliance were discovered and REE is reliant on control centre monitoring to detect any anomalies. It is not clear what specific parameters are monitored to ensure compliance and over what time period.

3.3 Germany

Germany is divided into 4 control areas managed by the TSOs EnBW, E.ON Netz, 50Hertz Transmission GmbH (formerly Vattenfall Europe Transmission) and RWE as illustrated in Figure 3.3.1. In this section, the relevant FRT requirements as outlined in the E.ON Netz Grid Code will be presented.

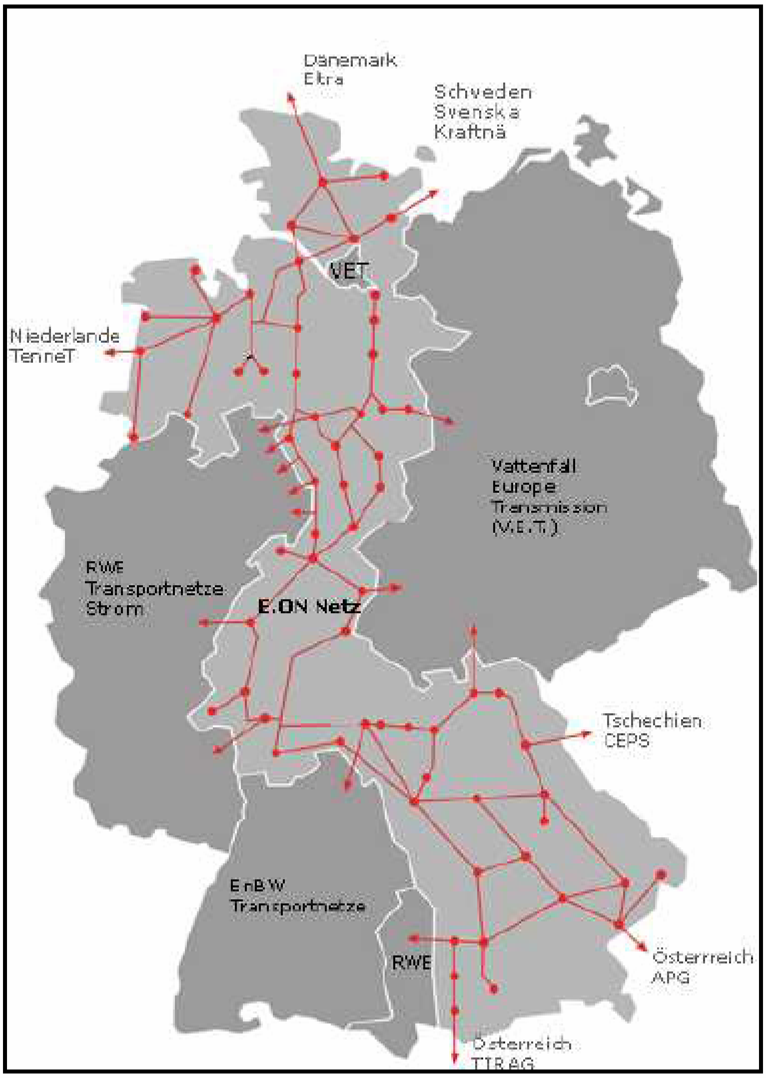


Figure 3.3.1. The control area of E.ON Netz (as per January 2006)

3.3.1 Main power system characteristics

The power system in Germany is an interconnected system with an installed capacity of about 129GW, total energy demand of approximately 449TWh and peak demand of approximately 78GW. The 380KV and 220kV electricity transmission system is shown in Figure 3.3.2.

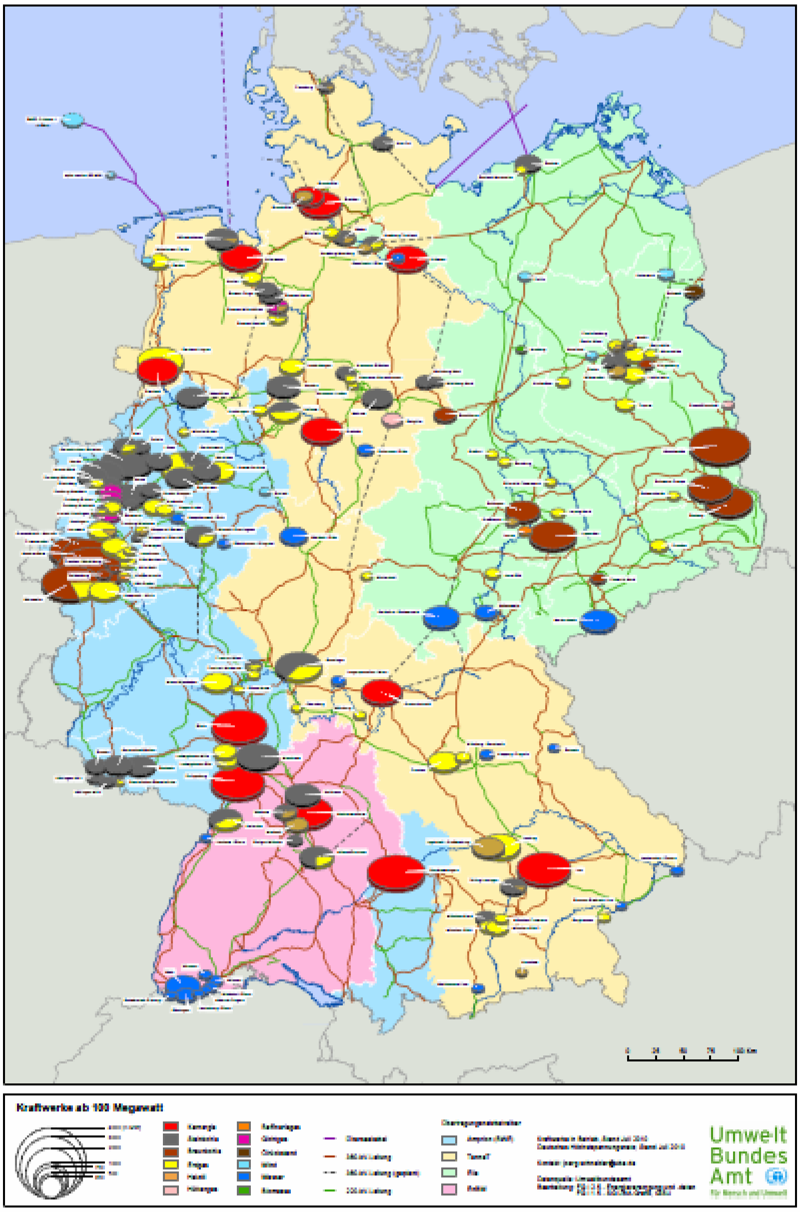


Figure 3.3.2. German Electricity Grid 2010

(http://www.umweltbundesamt.de/energie/archiv/kraftwerkskarte.pdf)

Two-thirds of electricity production is from fossil fuels (mostly coal), with the remaining third produced mostly from nuclear power along with wind power and small amounts of hydropower. Germany has decided to phase out nuclear power over the next two decades and is likely to replace it with a combination of gas-fired and coal-fired electricity as well as renewable energy. The consumption of renewable energy, and wind power in particular has been increasing rapidly; at the moment Germany has approx 45GW of coal power plants, more than 26GW of nuclear plants, 19.3GW of gas plants, 1.3GW of hydro power plant and 26GW of wind generation[17].

The German 380kV and 220kV grid is approximately 54,200km long[18] and forms part of the much stronger UCTE interconnected system on continental Europe.

Electricity imports come primarily from France, the Czech Republic, Norway, and Austria. Germany also exports small amounts of electricity to the Netherlands, Switzerland, and Austria.

3.3.2 Approach to FRT from historical perspective

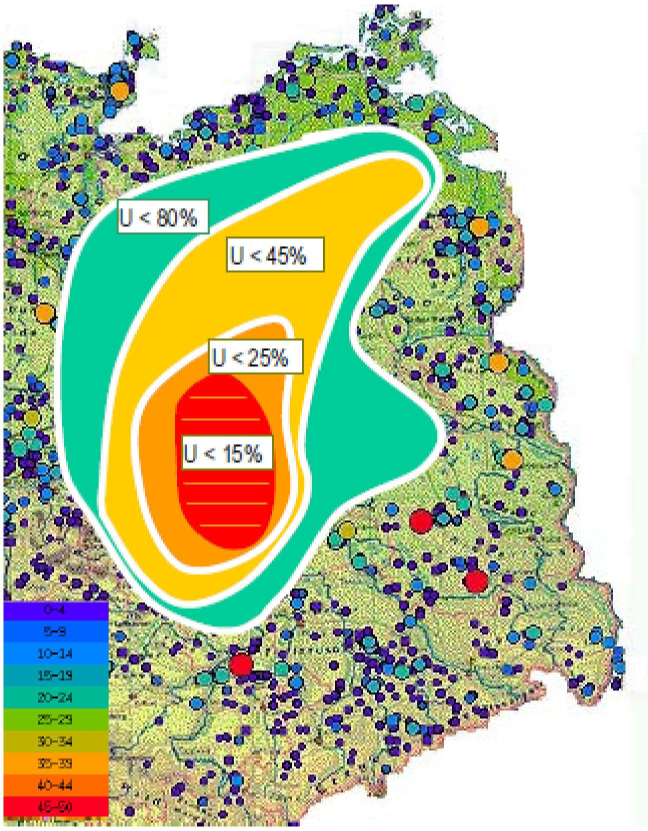
The Grid Code requirements including FRT requirements have been continually evolving over the last decade especially in relation to wind generation. Even though the requirements in relation to transient performance during voltage depressions have always been in existence, more specific changes in relation to FRT provisions of wind farms were introduced in the E.ON Grid Code of 2006 in response to a higher penetration of wind generation in certain regions. The most affected TOs have been E.ON and 50Hertz Transmission whose shares in total wind power generation are about 42% and 38% respectively. These TOs expressed early concerns and views suggesting that large wind farms have to be treated like conventional power plants in terms of their ability to ride through faults without disconnection.

Initial standard short-circuit calculations revealed that following a three-phase short circuit a large amount of installed wind power capacity may be lost if previous Grid Code rules were applied. Figure 3.3.3 illustrates an example case study conducted in the 50Hertz

[17] http://www.entso.eu

[18] The network data provided in the questionnaire response.

Transmission network[19]. In accordance with the previous practice, wind turbines would be disconnected from the grid when the generator terminal voltage fell below 80%.



Affected wind turbines: * installed capacity
U < 80% ➔ 2800 MW* (60%); U < 45% ➔ 2100 MW* (45%)
U < 45% ➔ 2100 MW* (45%); U < 25% ➔ 1400 MW* (30%)
U < 15% ➔ 1100 MW* (25%)

Figure 3.3.3. Voltage deviations during a 3-phase short circuit in the 50Hertz Transmission network

In the past, requirements for wind turbines were focused primarily on the protection of the wind generating units themselves and did not consider the impact that their disconnection may have on the power system. However, with the increasing share of wind generation and with the connection of wind farms directly to the high voltage grid, loss of a considerable part of the wind generation was considered unacceptable going forward.

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[19] I.Erlich, Grid Code Requirements concerning connection and operation of wind turbines in Germany, IEEE PES General meeting 2005.

Similarly, it was considered that the operation of wind generating plants with a fixed power factor couldn't be sufficient to meet the system needs. These plants should be required to participate in provision of voltage support and reactive power as needed depending on network demand and the actual voltage level.

As a result of these considerations, German transmission network operators, first of all E.ON, released the grid code requirements for connection of wind turbine generators to the grid. 50Hertz Transmission also published a grid code where renewable energy source requirements were addressed together with those of conventional power plants[20]. E.ON also consolidated its grid requirements for all generating plants into one grid code[21]. Simultaneously, the association of German transmission grid operators, VDN, summarized special requirements concerning renewable energy sources connected to the high voltage networks as an appendix to the existing general grid codes[22]. Contrary to previous rules, wind turbines are now required to be able to remain connected to the grid during and after network faults.

3.3.3 Existing FRT requirements

The fault ride through requirements of all generator types are set out in Section 3.2 of the E.ON “Grid Code High and Extra High Voltage[23]”, E.ON Netz GmbH, Bayreuth, April 2006[24].

The E.ON Grid Code defines minimum requirements for:

(a) Type 1 generating plants; i.e. synchronous generators connected directly to the grid; and

(b) Type 2 generating plants; i.e. all generators that do not meet the performance requirements and characteristics of type 1 generating plant. This type of generating plant covers wind and other 'unconventional' generation.

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[20] Vattenfall Europe Transmission, “ Rules of Vattenfall Europe Transmission GmbH for Network Connection and Utilization, http://transmission.vattenfall.de/

[21] E.ON “Grid Code High and Extra High Voltage”, E.ON Netz GmbH, Bayreuth, April 2006

[22] Verband der Netzbetreiber - VDN – e.V, “Renewable Energy Sources Connected to the High and Extra High Voltage Network”, ”EEGErzeugungsanlagen am Hoch- und Höchstspannungsnetz“, Guideline as attachment to the grid codes, VDN, Association of German Transmission Grid Operators, August 2003, http://www.vdn-berlin.de

[23] Extra high voltage is 220kV and above; high voltage refers to voltages between 60kV and 110kV.

[24] http://www.pvupscale.org/IMG/pdf/D4_2_DE_annex_A3_EON_HV_grid__connection_requirements_ENENARHS2006de.pdf

The FRT requirements that apply to Type 1 generating plant are summarised below. The requirements for Type 2 generating plant are described in Appendix A.3.

A Type 1 generating plant refers to a synchronous generator connected directly to the grid. Figure 3.3.4 shows the voltage duration curve at the grid connection point in the case of a three-phase short circuit. For voltages and durations above the red line, Type 1 generating plants should not become unstable and should not disconnect from the grid. This requirement, for fault-clearing times of up to 150 ms, applies to the entire operating range of the generating plant.

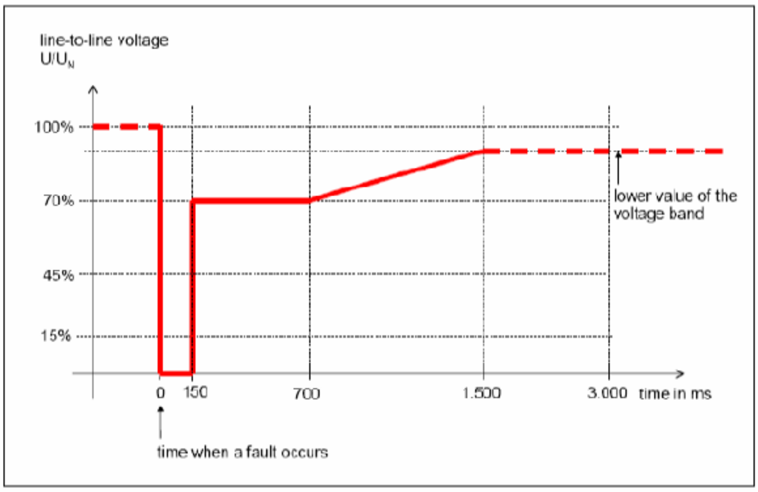

Figure 3.3.4 Voltage duration profile for Type 1, synchronous generating plant

3.3.4 **Compliance assurance**

German TSOs manage the connection application and the commissioning process for all power stations connected to their respective networks.

At the connection application stage the generator is responsible to provide all the necessary data and information so as to allow the TSO to assess the impact of the proposed connection on the network in relation to system capability, reactive power balance, fault level, etc. The TSO will conduct the FRT related studies only if the fault level is to be greater than or less than six times the rating of the generator. The standard connection application forms and guidelines on information exchange are provided in the TSO's grid code; these have to be kept up to date throughout the connection process. Basic information that needs to be provided by the generator at the application stage includes generating plant type and capacity, short circuit characteristics and transformer data. Additional information may be requested by the TSOs to include other equipment details, protection settings, voltage control provision and information in relation to steady state and dynamic behaviour of the generating plant and plant behaviour under abnormal voltage and frequency conditions etc. The TSO would normally provide the network data necessary for the generator to conduct relevant studies. In cases where initial investigations show that the proposed connection may have an adverse impact on the network and/or its users, the TSO would suggest modifications of the initial connection design including any need for reinforcements, if/as applicable. The generator connection design and settings are required to be compliant with N-1 security standard and all grid code (i.e. minimum) requirements; in some cases, it will be at the discretion of the TSO and generator to agree an alternative set of settings. Further site specific requirements may be specified in the bilateral agreement between the generator and the TSO.

The generator is required to submit evidence of compliance with the grid code before commissioning. The generating plant certification could form part of the compliance evidence.

E.ON's Grid Code provides details on the minimum information exchange and evidence required during the connection application and commissioning stages. Whilst provision of the evidence of compliance with the grid code including generating plant behaviour during abnormal voltage deviations have been indicated as being mandatory, no details are available in relation to the specific FRT related simulation studies or tests that are normally required to be undertaken by the generating plant and / or the TSO at the commissioning stage and during ongoing operations. Similarly, it is not clear how a lifetime compliance has been managed and enforced.

3.4 Denmark (Energinet.dk)

3.4.1 Main power system characteristics

The transmission system in Denmark consists of 400kV, 220kV, 150kV and 132 kV networks. Energinet.dk owns the 400 kV network, interconnections to neighbouring countries and the 132 kV grid in northern Zealand (see Figure 3.4.1), whereas the 150kV and 132 kV networks are owned by the regional transmission companies. Energinet.dk's 400kV transmission system is approximately 1,571km in length, comprising of 1,180km of overhead lines, 228km of cables and 163km of submarine cables. The regional 220kV network is approximately 500km in length and the 150kV & 132kV networks 4,223kms.

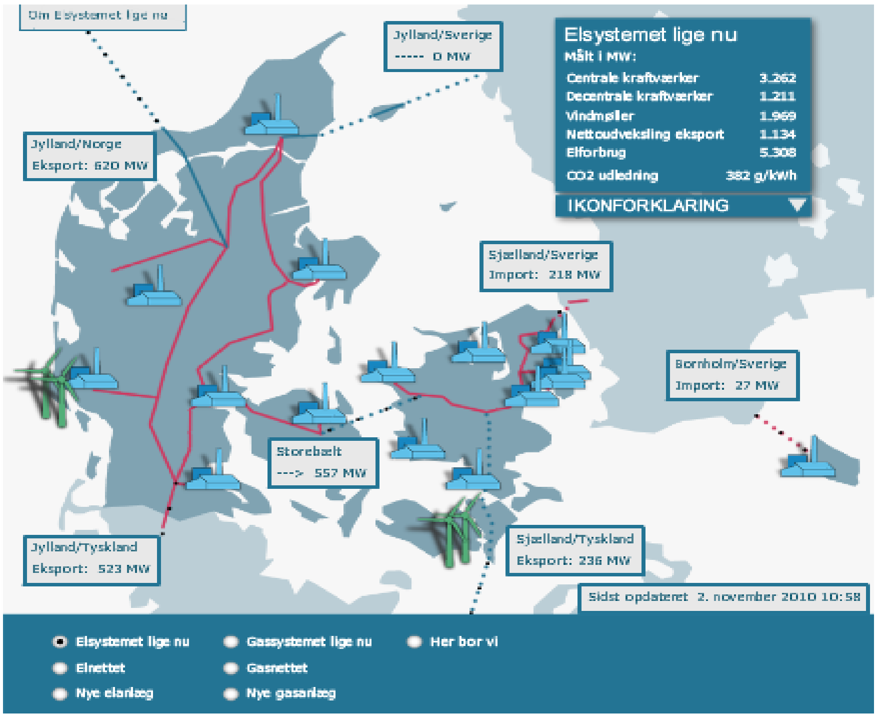

Figure 3.4.1 Energinet.dk 400kV Power System 2010 (http://www.energinet.dk/EN)

The maximum demand in Denmark is about 6.1MW with generation production of 34.7TWh met by installed generation capacities of[25];

- Fossil fuel 8,815MW,
- Wind 3,163MW, and
- Other renewables 640MW.

Approximately 20% of the total electricity consumption in Denmark was provided by wind power.

There is strong interconnection at all transmission voltage levels utilising both a.c. and d.c. technologies to Sweden (2,640MW capacity), Norway (1,040MW capacity) and Germany (2,100MW capacity).

The East Danish power system is synchronised with the Nordic system, whereas the West Danish power system is synchronised with the continental European system.

3.4.2 Approach to FRT from historical perspective

No information is available as to the historical evolution of FRT requirements. The requirements presented in Section 3.4.3 are regarded as a long-standing position in relation to generating plant behaviour under fault conditions.

3.4.3 Existing FRT requirements

Energinet.dk grid code requirements for fault ride through are specified in Technical Regulations for Grid Connection available at

http://www.energinet.dk/EN/El/Regulations/Technical-regulations/Sider/Regulations-for-grid-connection.aspx

25 https://www.entsoe.eu/index.php?id=65

There are two sets of specifications for connection at the transmission voltage levels, one for thermal plants and one for wind generators:

(a) Thermal power plants of 1.5MW or larger[26], and

(b) Wind Generators larger than 11 kW[27].

In this section, the FRT requirements for thermal generating plants with power output of 1.5MW or larger are presented. The FRT requirements for wind generators connected to voltages above 100kV are described in Appendix A.4..

A generating unit, including auxiliary supply system and auxiliary facilities, is required to stay connected to the grid during and after a voltage disturbance at the connection point as stated below with a subsequent maximum reduction in active power output of 10%.

Separate sets of requirements are defined for generator connections above 100kV and below 100kV.

a) Generator connection point above 100 kV

A power station unit must be able to withstand a nearby voltage disturbance on the high voltage side of the generator transformer and at the connection point as shown in Figures 3.4.2 and 3.4.3.

1) Faults near a power station – short line faults

A voltage disturbance near a power station means a voltage disturbance occurring at such a distance from a generating unit that, in the event of a three-phase short circuit, the share of AC in the initial short-circuit current from the power station unit's generator(s) is minimum 1.8 times the nominal current of the generators(s).

In the event of a three phase voltage disturbance, the generating unit must be

[26] Technical Regulations 3.2.3 for Thermal Power Station Units 1.5 MW or above Version 5.1, October 2008. This regulation replaces previous specifications and recommendations issued by Eltra and Elkraft, now merged into Energinet.dk, covering Western and Eastern Denmark, respectively.

[27] The new technical regulation 3.2.5 which is currently in translation replaces two current wind turbine regulations, ie: TF 3.2.5 for wind turbines connected to networks with voltages above 100 kV, and TF 3.2.6 for wind turbines connected to networks with voltages below 100 kV. Current technical regulations 3.2.5 and 3.2.6 for wind turbines were published by Elkraft System and Eltra in December 2004.

capable of withstanding a voltage duration profile as shown in Figure 3.4.2. In Eastern Denmark, duration y is required to be 250 ms (in accordance with Nordel requirements), and in Western Denmark, duration y is required to be 150 ms (in accordance with the existing UCTE requirements).

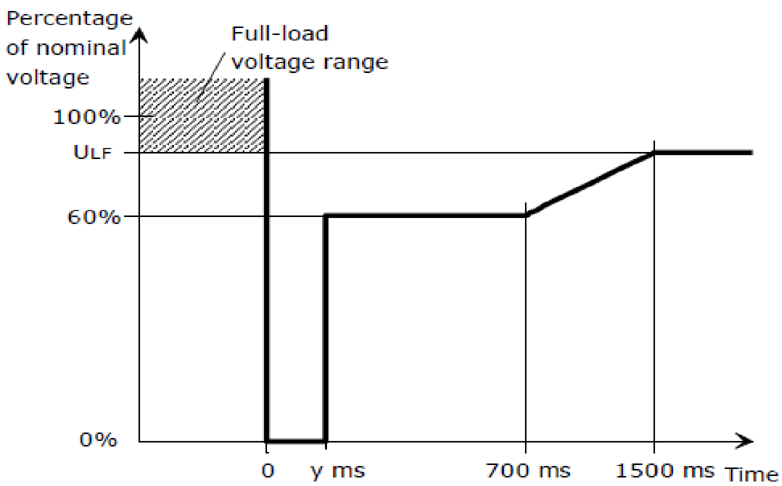

Figure 3.4.2. Three phase voltage-duration profile (U_{LF} is the lower limit of the allowed voltage range under full load)

In the event of one-phase or two-phase short circuits, the generating unit must be capable of meeting a voltage duration limit curve in the faulted phases as shown in Figure 3.4.3. At the same time the voltage in the healthy phases should be between the lower limit for the full-load voltage range (ULF) and 1.4 times the upper limit for the full load voltage range (1.4 x UHF). The time interval x, may vary between 300 ms and 800 ms.

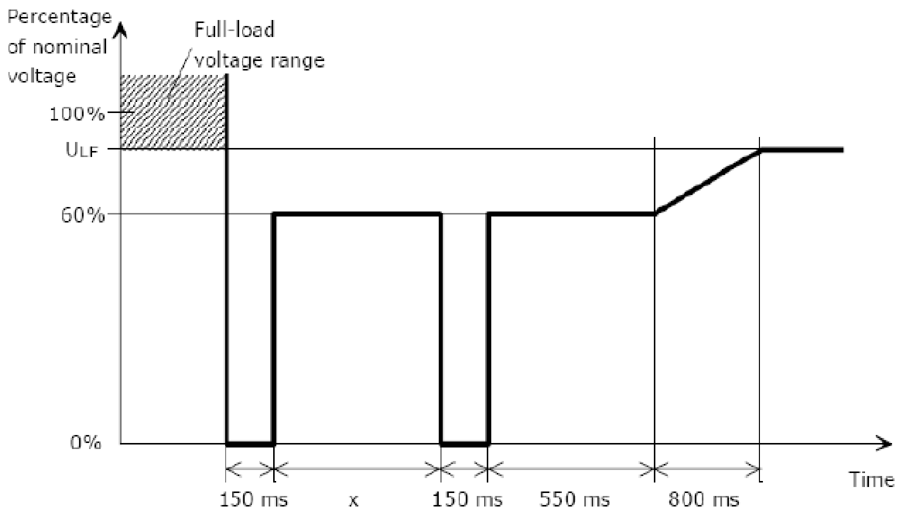

Figure 3.4.3. Phase Voltage-Duration Profile for thermal plants >1.5MW

2) Faults distant from a power station

A voltage disturbance distant from a power station means a voltage disturbance occurring at such a distance from the generating unit that, in the event of a three-phase short circuit, the share of AC in the initial short-circuit current from the power station unit's generator(s) is less than 1.8 times the nominal current of the generators(s).

A generating unit must be capable of tolerating any one, two or three-phase voltage disturbance far away from the power station for up to five seconds.

b) Generator connection point below 100 kV

A generating unit connection must be designed in such a way that the connecting points with nominal voltage up to 100 kV are able to withstand voltage dips up to 50% of the nominal voltage in all three phases for one second and to 0% of the nominal voltage in one phase during one second. They must also be capable of remaining connected during the voltage recovery profile shown in Figure 3.4.4.

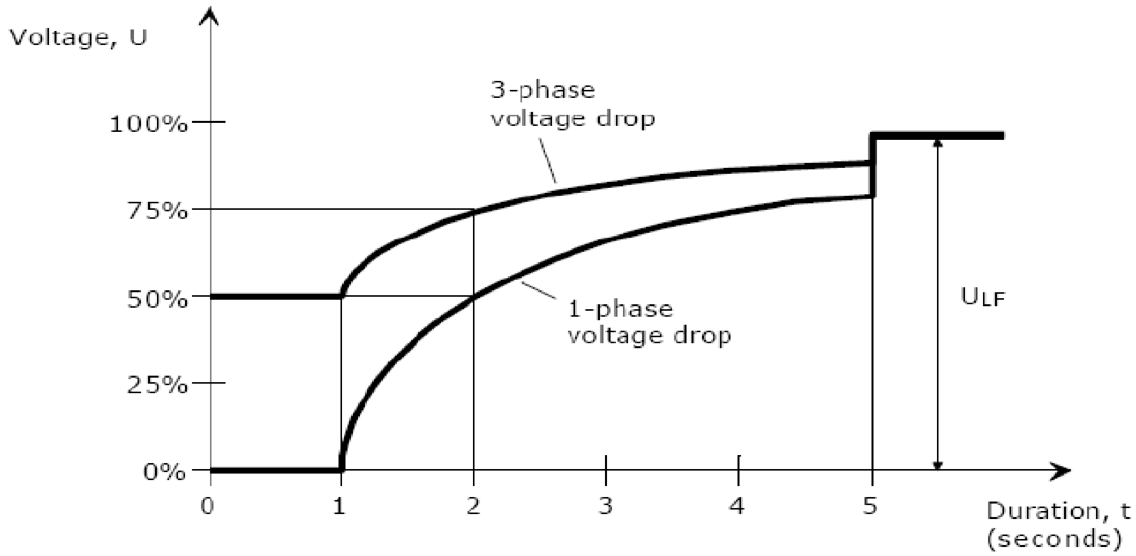

Figure 3.4.4. Relationship between duration and range of 1-ph and 3-ph voltage dips that generating units connected at voltages below 100 kV must be able to withstand

3.4.4 Compliance assurance

Technical regulations requirements are enforced by the individual electric power utilities. The TSO is responsible for ensuring that the regulations are adhered to and can, if applicable, issue an exemption from certain requirements within the regulations on a case by case basis. Any request for exemption must firstly be submitted to the electric power utility for comment before onward transmission to the TSO. The TSO is obliged to consult with relevant stakeholders before reaching its decision.

The compliance assurance process for thermal power plants is described below. For compliance considerations in relation to wind farms, see Appendix A.4.

The thermal power plant owner is required to provide, in an electronic form, all the information necessary for commissioning of its plant. The data and compliance evidence required during the commissioning process are specified in the Technical Regulations 3.2.3.

Prior to commissioning, the power plant owner should submit a study report comprising of relevant data and documentation including evidence of the generating plant behaviour under transmission network faults. The required FRT related information is shown in Table 3.4.2.

No.	Description	Value
N.1	Can *power station unit* remain synchronised during voltage disturbances	Yes ☐ No ☐
N.2	Documentation that generator can resist voltage disturbances without disconnecting (dynamic stability analysis or declaration from supplier)	
N.3	Documentation that auxiliary supply plant can withstand voltage disturbances (calculations or design philosophy)	
N.99	Comments	

Table 3.4.2 Required FRT related information at the pre-commissioning stage

Subject to the TSO's approval of the pre-commissioning information, the commissioning of the power plant can commence incorporating commissioning tests that satisfy the set of regulation requirements. There are no specific FRT tests that would need to be undertaken at this stage.

Upon preliminary approval of the commissioning test results (accompanied with recorded data) by the TSO, the power plant would be given a temporary operating permit with the final permit being granted upon final approval of all the documentation by the TSO.

The generating plant which does not receive an approval of its full commissioning documentation would be required to cease operation (e.g. it will be disconnected).

During the operational stage, the generator is required to continuously monitor the compliance of its plant. Any change in generating plant characteristics and/or performance must be reported to the TSO immediately along with the updated documentation. Generating plants larger than 25MW are required to notify the TSO immediately even in case of temporary changes (including outages) that may affect the plant compliance.

Any modification to the existing generating plant would require the same pre-commissioning and commissioning test process with final operating permit being granted only upon the TSO's approval of a complete commissioning documentation.

3.5 USA (ERCOT)

3.5.1 Main power system characteristics

The Electric Reliability Council of Texas (ERCOT) manages the flow of electric power to 22 million Texas customers - representing 85 percent of the state's electric load and 75 percent of the Texas land area. The ERCOT power system is not synchronously connected with the neighbouring systems (either the Eastern Interconnection or the Western Electricity Coordinating Council). Connections to other grids are limited to ties which allow the controlled transfer of power between the ERCOT system and another electrical system without the two systems being synchronised.

As the independent system operator for the region, ERCOT supplies power on an electric grid that connects 40,000 miles of transmission lines (which includes 8,000 miles of 345kV lines and 16,000 miles of 138kV lines) and more than 550 generation units. The power system has an installed capacity of approximately 84GW (see Figure 3.5.1), total energy demand of about 308TWh and peak demand of about 66GW.

Figure 3.5.1 indicates ERCOT's jurisdiction, with the square box highlighting the area of greatest concentration of wind farms. There is currently 9.3GW of wind generation capacity connected and operating in the ERCOT system – more than any other state in the country with additional 44GW under development. Almost 90 percent of the wind is located in West Texas, away from the primary load centres.

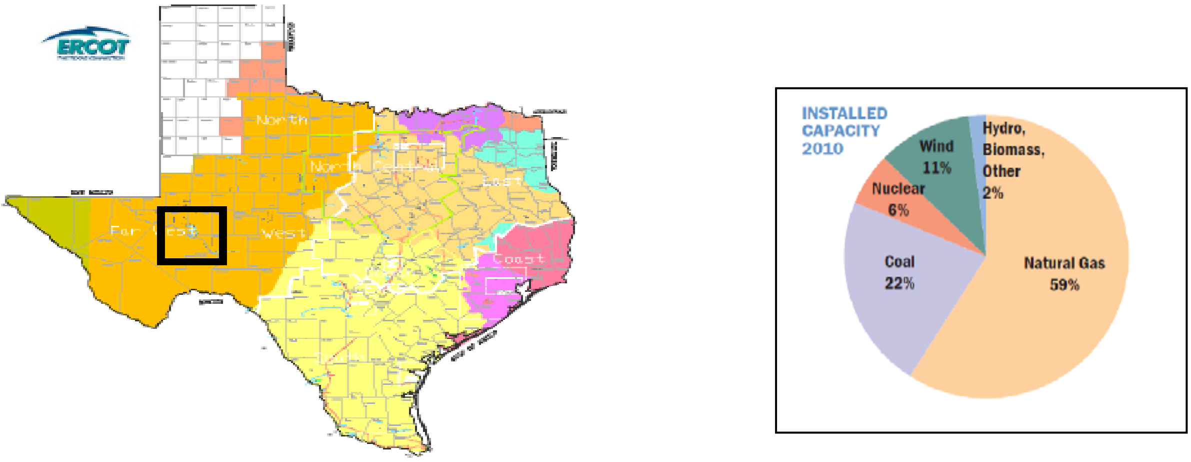

Figure 3.5.1. ERCOT's power-system network and installed generation capacity 2010. (http://www.ercot.com/content/news/presentations/2010/2009%20ERCOT%20Annual%20Report.pdf)

3.5.2 Approach to FRT from historical perspective

The majority of the initial wind generation built in Texas was in the West Texas area which had a very weak transmission system. As penetration of wind generation has increased, ERCOT has worked with generation owners and market participants to improve the tools for managing the operational challenges associated with the variability and uncertainty of wind generation, particularly in the areas of dispatching, forecasting, ancillary services, accurate modelling, and connection standards. In close relation to the latter, ERCOT had an incident where there was a major fault in the West Texas area and all of the wind generation was lost, even those units that were some electrical distance from the fault. This event was a key precipitating factor for the ERCOT staff to start developing new connection requirements for FRT.

The FRT issue was discussed formally for the first time at the meeting of the Generator Interconnection committee held in August 2006 under the agenda item, "Add Low Voltage Ride Through (LVRT) capability as outlined in NERC/FERC requirements for wind farms signing interconnection agreements as of January 1, 2007". Further meetings and development of requirements and compliance procedures followed.

Voltage support has traditionally been provided by conventional (fossil) generation, but higher penetration of wind generation and decrease in fossil generation has become a more likely scenario going forward. The wind generator technologies have however varying capabilities for remaining online through brief dips in transmission voltage. Even though such dips are considered rare, they can be wide-spread across the transmission network in the event of a severe (3-phase) transmission line fault. Without low voltage ride-through, many wind generators could trip simultaneously, increasing system generation lost for a single contingency. In order to preserve overall system stability and security of supply, wind generating plants are now required to provide voltage support and primary frequency response and meet voltage/fault ride-through requirements when a fault occurs on the transmission system as specified in the ERCOT Operating Guides of 1 July 2010[28].

3.5.3 Existing FRT requirements

The minimum requirements for all generating plants greater than 10MW connecting to the ERCOT network are specified in the ERCOT Operating Guides of 1 July 2010[29]. There are currently no explicit FRT requirements and generating plants are only required to set generator voltage relays so as to remain connected to the transmission system during the following operating conditions:

- Generator terminal voltages are within five percent (5%) of the rated design voltage and volts per hertz are less than one hundred five percent (105%) of generator rated design voltage and frequency;
- Generator terminal voltage deviations exceed five percent (5%) but are within ten percent (10%) of the rated design voltage and persist for less than 10 seconds;
- Generator volts per hertz conditions are less than one hundred sixteen percent (116%) of generator rated design voltage and frequency and last for less than 1.5 seconds;
- A transmission system fault (three-phase, single-phase or phase-to-phase), but not a generator bus fault, is cleared by the protection scheme coordinated between the generator and the transmission service provider on any line connected to the generator's transmission interconnect bus, provided such lines are not connected to induction generators. However, in the case of a generator bus fault or a primary transmission system relay failure, the generator protective relaying may clear the generator independent of the operation of any transmission protective relaying.

[28] ERCOT Operating Guides, 1 July 2010. http://www.ercot.com/mktrules/guides/operating/current
[29] ERCOT Operating Guides, Section 3, 1 July 2010. http://www.ercot.com/mktrules/guides/operating/current

3.5.4 Compliance assurance

Connection of new generating plant to the ERCOT transmission grid is required to be in accordance with the ERCOT Standard connection agreement and procedures. The commissioning and initial synchronisation checklists have to be submitted to ERCOT confirming compliance with ERCOT Protocols and Operating Guide[30].

Any equipment changes that may affect the reactive capability of an operating generating unit should be reported to ERCOT and the Transmission Service Provider within sixty days prior to implementation. Changes that decrease the reactive capability of the generating unit below the required level and changes that decrease the Voltage Ride-Through (VRT) capability of the plant must be approved by ERCOT prior to implementation.

[30] ERCOT New Generator Commissioning Checklist, July 2009.

3.6 Australia (Western Power)

3.6.1 Main power system characteristics

The South West Interconnected System (SWIS) operated by Western Power is the primary electricity grid in Western Australia, spanning the area from Kalbarri in the north to Kalgoorlie in the east and through to Albany in the south. The SWIS is a comparatively small power system and is geographically isolated from the interconnected power systems of Eastern and Southern Australia. It consists of around 96,000 km of powerlines (transmission & distribution) with a peak demand of approximately 4GW.

Figure 3.6.1: Western Australia SWIS transmission area

The transmission network has no interconnection and is predominantly overhead with a total network length of some 6,690kms consisting of;

- 800kms at 330kV,
- 650kms at 220kV,
- 4,000kms (plus 20km cable) at 132kV, and
- 1,200kms (plus 20kms cable) at 66kV.

The majority of connected generation capacity is thermal and totals some 5,400MW with the following constituents;

- 30% coal,
- 35% gas,
- 30% dual gas/oil or gas/coal, and
- 5% wind.

This network data was provided by Western Power in the questionnaire response.

3.6.2 Approach to FRT from historical perspective

It is understood from Western Power that FRT requirements for conventional generation existed prior to 1997 but the relevant documentation has not been obtained to verify this. These requirements, however, are likely to have been on the basis of the broad generic principals stated in 3.6.3.

Following the Electricity Act 2004 the Government of Western Australia produced the Electricity Network Access Code 2004,[31] administered by the Office of Energy. One of the requirements of the Access Code, Chapter 12, is that network service providers (NSP) must produce and publish Technical Rules.

[31]http://www.energy.wa.gov.au/cproot/1370/2/ENAC%20%20Unofficial%20consolidated%20version.pdf

Western Power, as an NSP, published its Technical Rules in September 2007.[32] These Rules cover the SWIS, and detail the technical requirements to be met by Western Power on the transmission and distribution systems and by Users who connect facilities to the transmission and distribution systems.

Section 3 of the Technical Rules concerns the Technical Requirements of User Facilities, with sub-section 3.3 detailing specific Requirements for Connection of Generating Units with a combined rating of 10MW or greater.

The further, detailed requirements for all Generating Unit Response to Disturbances in the Power System are set out in clause 3.3.3.3. and include;

b) Immunity to frequency excursions,
c) Immunity to voltage excursions,
d) Immunity to rate of change of frequency,
e) Immunity to high speed auto-reclosing,
f) Post-fault reactive power of a power station with non-synchronous generating units,
g) Post fault voltage control of a connection point, and
h) Continuous uninterrupted operation (definition).

3.6.3 Existing FRT requirements

In addition to the four key requirements related to voltage, frequency, rate of change of frequency and high speed auto reclosing, Western Power adopt the generic principles that;

- each generator should withstand all faults that would not otherwise disconnect the generator,
- no single fault should result in multiple generator outages, and
- the FRT requirements should facilitate the current and targeted level of the particular type of generation in the (specific) part of the power system.

The low voltage FRT requirements reproduced from the Western Power Technical Rules are;

[32] http://www.westernpower.com.au/documents/aboutus/accessarrangement/2007/Technical%20Rules/TECHNICALRULES.pdf

(c) **Immunity to *Voltage* Excursions**:

(1) A *generating unit* and the *power station* in which the *generating unit* is located must be capable of continuous uninterrupted operation:

(A) for the range of *voltage* variations permitted by clause 2.2.2; and

(B) for *transmission or distribution system* faults which cause the *voltage* at the *connection point* to drop below the nominal *voltage* for a period equal to the circuit breaker failure fault clearing time to clear the fault plus a safety margin of 30 msec, followed by a period of 10 seconds where the *voltage* may vary in the range 80% to 110% of the nominal *voltage*, and a subsequent return of the *voltage* within the range 90 to 110% of the nominal *voltage*.

The resulting low voltage FRT requirement for all generating units 10MW and greater is zero volts for a duration of 0.45s, as illustrated in Figure 3.6.2.

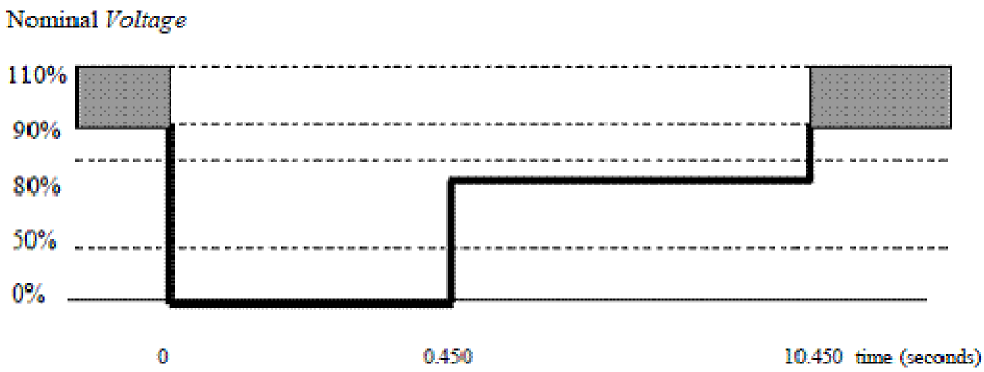

Figure 3.6.2: Western Power low voltage FRT requirement for all generation units of 10MW capacity or greater

Western Power notes that the above duration figure was derived for the worst case back-up protection clearing time on the 330kV network, plus a 30ms margin. It is a more onerous requirement than that of the National Electricity Market in eastern Australia of zero volts for a duration of 0.175s.

(e) **Immunity to High Speed Auto Reclosing**:

A *generating unit* and the *power station* in which the *generating unit* is located must be capable of continuous uninterrupted operation for *voltage* transients caused by high speed auto-reclosing of *transmission* lines irrespective of whether or not a fault is cleared during a reclosing sequence.

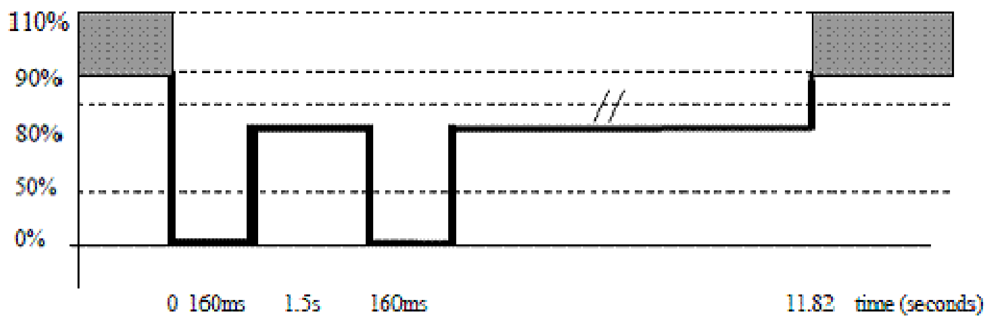

Figure 3.6.3: Requirement for generating units during auto-reclose operation

These requirements apply to both synchronous and non-synchronous generation. Non-synchronous generators are however required to comply with certain additional requirements; for details, see Appendix A.6.

3.6.4 Compliance assurance

On completion of preliminary consultation to explore the most viable connection option in terms of available network capacity and any necessary upgrades the connection applicant will submit a formal access application.

The access application will include a full set of generation unit data as specified in Attachment 4, Large Generating Unit Design Data, of the Technical Rules.

It is then up to the applicant to employ a suitable party, which could be WP, to perform the appropriate studies to demonstrate compliance with section 3.3 of the Technical Rules. Western Power will often perform its own studies to verify the results provided by the applicant.

The connection requirements for compliance with the Technical Rules are clearly stated in section 3.3;

3.3 REQUIREMENTS FOR *CONNECTION* OF GENERATING UNITS

3.3.1 General

(a) A *Generator* must comply at all times with applicable requirements and conditions of *connection* for *generating units* as set out in clause 3.3.

There is also an obligation in the Technical Rules on the generator to verify compliance of its own equipment;

3.3.3 Detailed Technical Requirements Requiring Ongoing Verification

A *Generator* must verify compliance of its own *equipment* with the technical requirements of this clause 3.3.3 by the methods described in clause 4.1.3.

It is not made clear what information should be submitted, and how often, to demonstrate ongoing compliance.

Section 4, Inspection, Testing, Commissioning, Disconnection and Reconnection of the Technical Rules contains clause 4.1.3 relating to Tests to Demonstrate Compliance with Connection Requirements for Generators. This clause is fairly comprehensive running to four pages and sub-clauses (a) to (h). For example;

4.1.3 Tests to Demonstrate Compliance with Connection Requirements for Generators

(a) (1) A *Generator* must provide evidence to the *Network Service Provider* that each of its *generating units* complies with the technical requirements of clause 3.3, 0 or 3.7, as applicable, and the relevant *connection agreement* prior to commencing commercial operation. In addition, each *Generator* must cooperate with the *Network Service Provider* and, if necessary, *System Management* in carrying out *power system* tests prior to commercial operation in order verify the performance of each *generating unit*, and provide information and data necessary for computer model validation. The test requirements for *synchronous generating units* are detailed in Table A11.1 of Attachment 11. The *Network Service Provider* must specify test requirements for non-synchronous *generation*.

The Table A11.1 in Attachment 11, Test Schedule For Specific Performance Verification And Model Validation referred to contains the conditions and schedules of test required to assure compliance with the Technical Code. It would appear that there is no specific FRT test and that this is assured from the provision of necessary data to validate model results.

Western Power also require that compliance tests must only be performed after the machines have been tested and certified by a Chartered Professional Engineer with National Professional Engineers' Register standing, qualified in a relevant discipline.

In the event that a serious non-compliance is detected, then no connection is allowed. For less serious breaches permission for temporary connection (with no option to extend) of sufficient duration for the non-compliance to be rectified is granted..

Western Power also has a guidance document for generators that cannot comply with all requirements of the Technical Code and require to seek an exemption; Guidelines For Requests for Exemptions from Compliance with the Technical Rules for the South West Interconnected Network, May 2010.[33]

The request for an exemption from compliance with the Technical Rules should be a last resort to be considered only after all reasonable steps to comply have been taken and options have been demonstrably exhausted. Any such request must clearly state what the User wants and why, and what the User did in order to attempt to comply, supported by evidence and reasoning.

All technical and Rules related arguments must be signed by a Chartered Professional Engineer with NPER standing.

33

http://www.westernpower.com.au/documents/aboutus/accessarrangement/2010/Guidelines_for_requests_for_exemptions_May_2010.pdf

3.7 New Zealand

3.7.1 Main power system characteristics

Transpower owns and operates the transmission network in New Zealand as shown in Figure 3.7.1. The core of the National Grid is the 220 kV network in each island and the HVDC link between them. Provincial centres and smaller power stations are connected by transmission lines operating at 110kV, 66kV and 50kV.

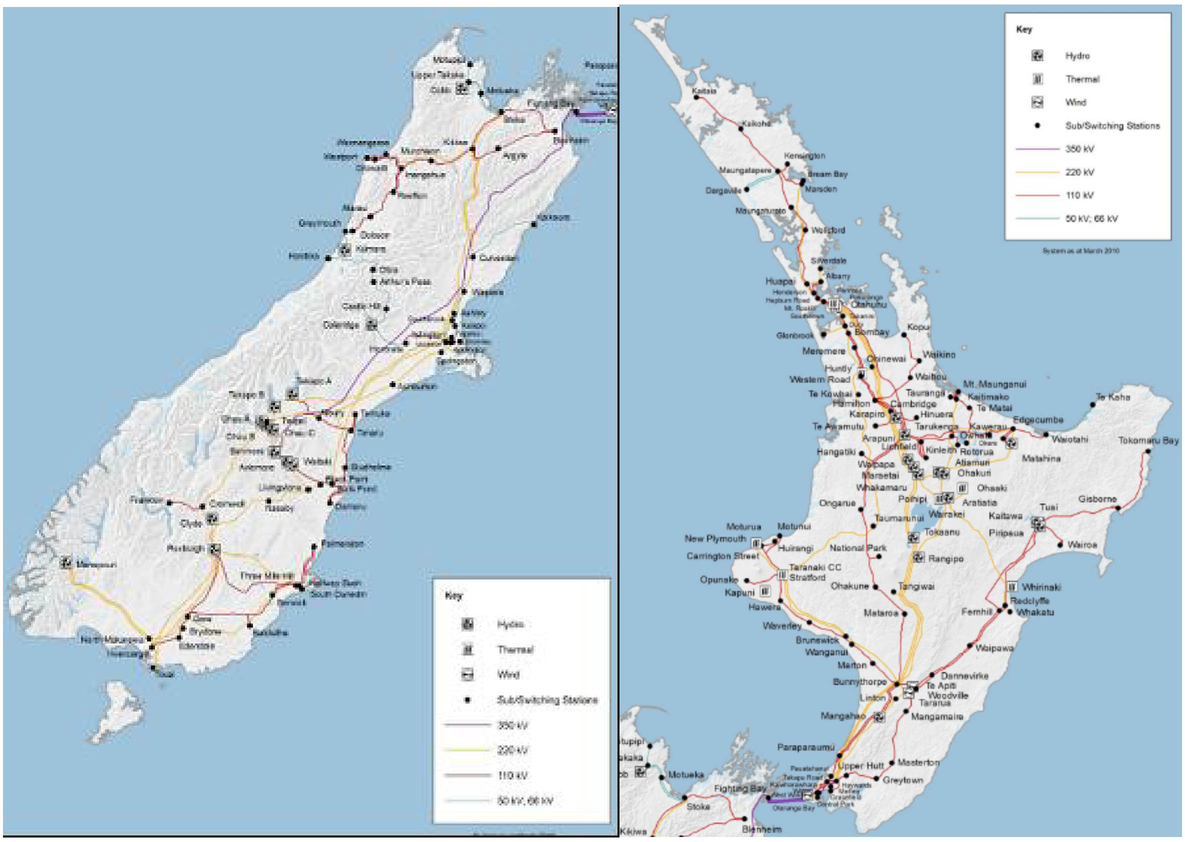

Figure 3.7.1: South and North Island transmission networks

The transmission system network is not as robust as continental European networks and has no interconnection apart from the HVDC link connecting the two islands. The network is approximately12,961km in length with underground cable accounting for just 84km.

The total maximum demand annually is approximately 40TWh with peak demands of 4,500MW in the North Island and 2,300MW in the South Island. The connected generation capacity supplying this demand is;

- Thermal 2,852MW,
- Firm renewables (largely hydro) 6,120MW,
- Wind 496MW, and
- Other renewable 19MW.

Data from Commerce Commission web site.[34]

3.7.2 Approach to FRT from historical perspective

The Electricity Commission in New Zealand was established in 2003 to oversee New Zealand's electricity and markets with the associated Electricity Governance Rules (EGRs) established in December 2003.[35] These rules are inherited from the electricity industry's self-governing arrangements which existed prior to the Commission's establishment .

The relevant part of the self-governing arrangements with respect to voltage criteria was known as the Common Quality Obligations (CQO) but was very loose in its wording and participants were not legally obligated to meet the requirements. There was no defined low voltage or fault ride through capability.

Post 2003 and the establishment of the EGRs through several revisions to the present day, there remain no technical requirements for generator FRT capability. However, in 2008 the Electricity Commission and Transpower recognised it would be prudent to specify a fault ride through capability for generators and initiated a suitable investigation to determine an appropriate Voltage Ride Through (VRT) requirement for incorporation into the Electricity

[34] www.comcom.govt.nz
[35] http://www.electricitycommission.govt.nz/rulesandregs/rules

Governance Rules and Regulations. This study has been completed and is currently under industry consultation and is described in section 3.7.4 of this report.

3.7.3 Existing FRT requirements

The current version of the EGRs is dated September 2nd 2010 and the only reference to voltage support is specified in Part C Common Quality, Section III Asset Owner Performance Obligations (AOPO), Rule 3.2 – Voltage support AOPOs. It states;

> **3.2 Voltage Support AOPOs**
>
> Each **generator** with a **point of connection** to the **grid** will at all times ensure its **assets**:
>
> **3.2.1 Exporting net reactive power at full load**
>
> When the voltage at its **grid injection point** is within the applicable range of nominal voltage, are capable of exporting (over excited) when **synchronised** and made available for dispatch by the **system operator**, a minimum net **reactive power** which is 50% of the maximum continuous megawatt (**MW**) output power as measured at the **generating unit** terminals as set out below:
>
> **3.2.2 Importing net reactive power at full load**
>
> When the voltage at its **grid injection point** is within the applicable range of nominal voltage, are capable of importing (under excited) when synchronised and made available for dispatch by the **system operator**, a minimum net reactive power which is 33% of the maximum continuous megawatt (**MW**) output power as measured at the **generating unit** terminals as set out below:
>
> **3.2.3 Support voltage in order to prevent system collapse**
>
> when **synchronised**, continuously operate in a manner that supports voltage and voltage stability on the **grid** in compliance with the **technical codes.**

The last requirement is the only rule that can be referenced to a generator's capability for FRT and is a key factor in assisting the System Operator to meet the principal performance obligations (PPOs) to avoid cascade failure.

The current practice for new generator connections to determine FRT requirements is for the generator asset owner to approach Transpower Grid Planning to conduct site specific power system studies. Additionally, the generator asset owner may contract an external party or Transpower to perform studies if it is deemed that there may be specific power system issues at the proposed site.

3.7.4 Proposed FRT requirements

In 2008 the Electricity Commission and Transpower recognised it would be prudent to specify a fault ride through capability for generators and initiated a suitable investigation to determine an appropriate Voltage Ride Through (VRT) requirement for incorporation into the Electricity Governance Rules and Regulations.

The investigation had two stages:

1. Literature Review / Data Collection
2. Power System Dynamic Studies

Stage 1 has been completed and reviewed existing grid planning criteria, protection requirements, previous ride through studies, international standards and the ability of generators to meet FRT criteria[36].

Stage 2 involved power system studies to determine current and future system performance, and analysis of material presented in stage 1 in order to determine a suitable FRT envelope that will provide a requirement for generators wishing to connect to the power system. The results were published in May 2010[37].

The studies considered only those contingencies that had an inter-region impact and FRT results seem to be predominantly influenced by protection scheme operating characteristics.

During the studies it was found there was sufficient difference in the performance of the systems in the North and South Islands to warrant separate FRT capabilities. The proposed

[36] http://www.ea.govt.nz/our-work/programmes/pso-cq/fault-ride-through/

[37] System Operator Report: Generator Fault Ride Through (FRT) Investigation: Stage 2, Transpower, 04/05/2010.

FRT voltage envelopes for the North and South Island are shown in Figure 3.7.2 and Figure 3.7.3 respectively. There are committed system performance improvement projects proposed or underway that will lead to the future harmonisation of FRT requirements in the North and South Islands.

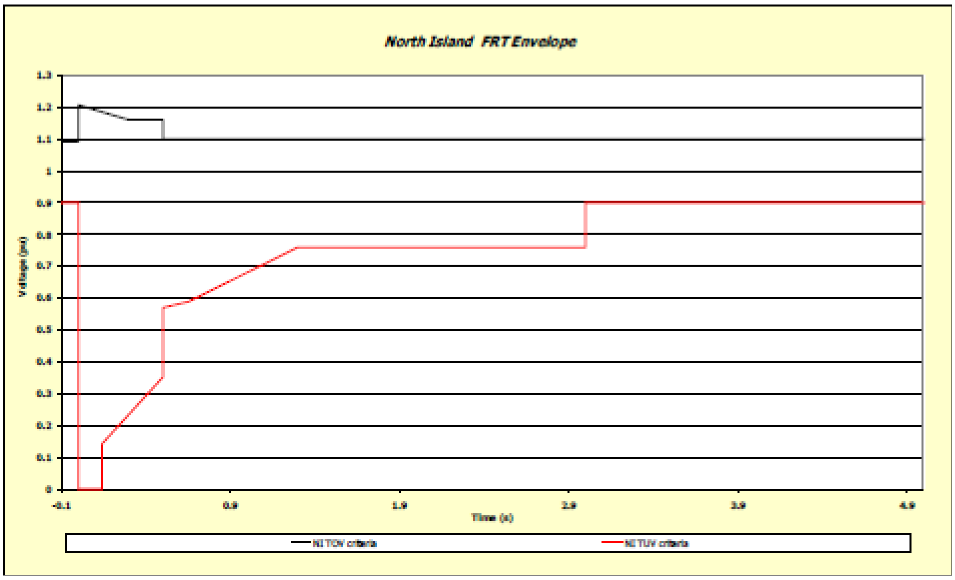

Figure 3.7.2: Proposed North Island FRT envelope

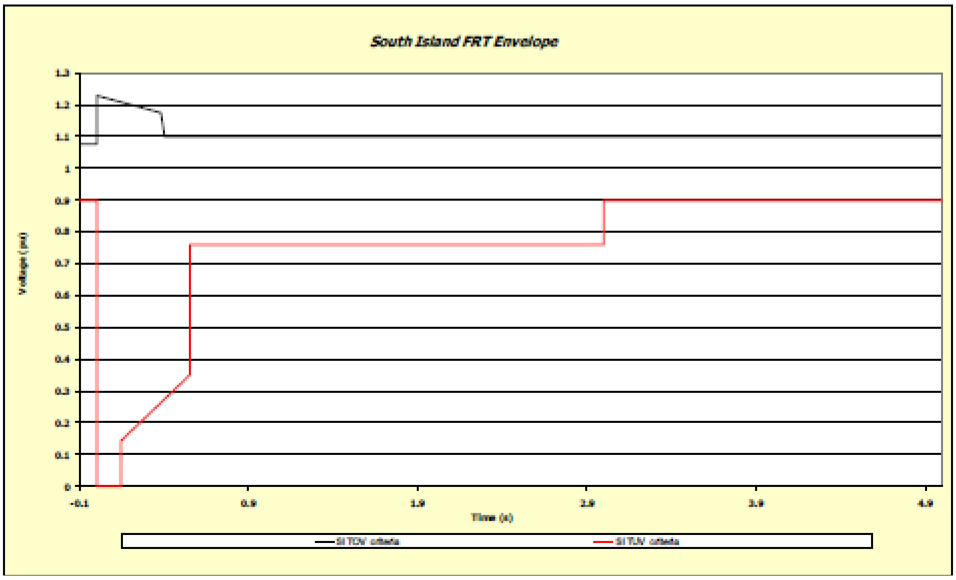

Figure 3.7.3: Proposed South Island FRT envelope

Amendment of the EGRs to accommodate the proposed FRT capabilities is currently under consultation with the Electricity Commission. The amendment will also take into account the proposed FRT requirements for on wind generators; for details, see Appendix A.7.

3.7.5 Compliance assurance

There are no compliance requirements defined in the EGRs as they currently stand but Transpower has produced an asset testing Explanatory Guide in response to, and based on, the Electricity Commission's consultation paper on the Routine Testing of Assets. As the rules for routine testing of assets have not yet been finalised by the EC the Explanatory Guide[38] is a live document and will be updated on publication of the final rules.

The guide sets out the tests considered appropriate by Transpower for asset owners (generator, grid and distributor) to demonstrate asset compliance with technical codes. Section 2 of the guide pertains to generator tests with sub-section 2.1 covering Routine Tests and sub-section 2.2 dealing with Initial Tests Commissioning/Modification.

The routine tests of sub-section 2.1 are designed to ensure that the generator is able to meet the requirements of the Technical Codes and that results provide sufficient information to verify;

- Operational ranges and limits of the generating plant,
- Steady-state and dynamic performance of the plant,
- Over/under frequency performance as well as trip settings, and
- Compliance of the protection systems with the protection related AOPOs and Technical Codes.

The test and information requirements to satisfy the required outcomes above are detailed in the following sections of the Explanatory Guide;

2.1.2 Generating unit frequency response

2.1.3 Generating unit governor and frequency control

[38] http://www.systemoperator.co.nz/f1684,38911350/GL-EA 10_Companion_Guide_for_Testing_of_Assets.pdf

2.1.4 Generating unit transformer voltage support

2.1.5 Generating unit voltage response and control

2.1.6 Generator protection systems

Section 2.1.5 details the test requirements of the exciter and setting parameters of synchronous generators and the mode of control, setting parameters and reactive power compensation requirements of asynchronous generators. No specific mention is made of fault ride through requirements.

Sub-section 2.2 Initial Tests Commissioning/Modification details the generator tests required during commissioning or following modification to confirm asset capability and provide up to date ACS (Asset Capability Statement) information. The generator tests apply to all generators above 1MW in size whether connected to the grid or embedded in a local network.

The test and information requirements to satisfy the required outcomes above are detailed in the following sections of the Explanatory Guide;

2.2.2 Generating unit parameters

2.2.3 Generator frequency performance

2.2.4 Generator transformers

2.2.5 Generating unit exciter/AVR and voltage control,

2.2.6 Generating unit governor/turbine and frequency control, and

2.2.7 Generator protection.

Section 2.2.5 only applies to grid connected and embedded generators that materially affect voltage at the Grid Supply Point. No specific mention is made of fault ride through requirements.

It should be noted that with the Transpower proposal to introduce FRT requirements to the Electricity Governance Rules currently under consultation with the EC and the WGIP recommendation that fault ride through requirements should be established for wind generators, it is likely that such requirements will be reflected in future versions of the Explanatory Guide for asset testing.

4 SUMMARY TABLES OF INTERNATIONAL FRT REQUIREMENTS

A summary of FRT requirements specified in different Grid codes and / or technical standards and rules together with their development, network characteristics and compliance assurance considerations is given in Tables 4.1-4.6.

Table 4.1 Network Characteristics

Transmission Network Characteristics					
Country TSO	**Generation Capacity (MW)**	**Max Demand (GW)**	**Capacity Wind (% of total)**	**Network Length (kms) & (% o/h)**	**Network Voltage (kV)**
Ireland	6,400	4.9	23%	6,844 (96%)	110, 220, 400
Great Britain	74,000	58	4%	23,830 (95%)	275, 400
Spain	94,000	45	20%	34,993 (99%)	220, 400
Germany/ E.ON Netz	129,000	78	20%	35,864 (99%)	110, 200
Denmark (Energinet.dk)	12,618	6.1	25%	4,223 (?%)	132, 150, 400
USA / ERCOT	84,545	66	11%	70,400 (99%)	138, 345
Australia (Western Power)	5,400	4	5%	6,690 (99%)	66,132, 220, 330
New Zealand	9,487	6.8	5%	12,960 (98%)	50, 66, 110, 220

Table 4.2 Requirement Codes and Documents

Fault Ride Through Requirements – Applicable Codes & Documents					
Country TSO	**Long Term Requirement**	**Recent Requirement**	**Revision**		
Ireland	None prior to 1997.	Interim Grid Protocol July 1997.	Grid Code v1 Dec 2001.	WFPS incorporated in Grid Code Jul 2004. (wind)	Grid Code v3.4 Oct 2009.
Great Britain	CEGB Standards: PLM-SP-1 1975 PLM-ST-4 1975 Op.Mem.3 1989	Grid Code	Grid Code 2005 (incorporating onshore & offshore wind)	Grid Code Oct 2010.	
Spain	None prior to 2005.	Ministerial Order: P.O.12.2 Feb 2005 for conventional. P.O.12.3 Oct 2006 for non-synchronous.	P.O.12.2 currently under review.		
Germany/ E.ON Netz	Long standing conventional transient capability. Source document not found.	Grid Code HV & EHV.	Grid Code HV & EHV Apr 2006. (consolidated for all generators)		

Fault Ride Through Requirements – Applicable Codes & Documents (continued)					
Country TSO	**Long Term Requirement**	**Recent Requirement**	**Revision**		
Denmark (Energinet.dk)	Wind connection conditions back to 1999 but not know if FRT included.	Technical Regulations: 3.2.3 v5.1 Oct 2008 for conventional. 3.2.5 & 3.2.6 Dec 2004 for wind.	Technical Regulation 3.2.6 revised 2010. (not yet translated)		
USA / ERCOT	None as conventional generation viewed as inherently capable.	ERCOT Operating Guide Nov 2008. (FRT wind specific).	ERCOT Operating Guide Jul 2010 (all generators >10MW)		
Australia (Western Power)	Long standing conventional transient capability. Source document not found.	Government of WA Electricity Network Access Code 2004.	Western Power Technical Rules Sept 2007. (all generators>10MW)		
New Zealand	None.	Electricity Governance Rules (EGR) 2003 to Sept 2010 do not state any FRT requirement.	FRT review commenced 2008.	Proposal for FRT incorporation into EGRs currently under consultation.	

Table 4.3 Conventional Generator FRT Requirements

Fault Ride Through Requirements – Conventional Generator					
Country TSO	**Voltage Level (kV)**	**Min. Voltage (% Un)**	**Fault Duration (ms)**	**Voltage Recovery (% Un, time)**	**Comment**
Ireland	110, 220, 400	5	200	100%	Gen Plant >2MW
Great Britain	275, 400	0 15	<140 >140	90% within specified time 90% after 3 minutes	Gen Plant installed after 1/04/05.
Spain	220, 400	0 20	150 500	95% after 15s	
Germany/ E.ON Netz	110, 200	0	150	Umin after 1.5s	Type 1 generator.
Denmark (Energinet.dk)	132, 150, 400	0	250 (east) 150 (west)	60% in 700ms, Umin after 1.5s	Gen Plant >1.5MW
USA / ERCOT	138, 345	unspecified	unspecified	unspecified	Gen Plant >=10MW
Australia (Western Power)	66,132, 220, 330	0	450	90% after 10.45s	Gen Plant >=10MW
New Zealand	50, 66, 110, 220	none	none	none	In consultation

Table 4.4 Non-synchronous Generator FRT Requirements[39]

Fault Ride Through Requirements – Non-synchronous Generator					
Country TSO	**Voltage Level (kV)**	**Min. Voltage (% Un)**	**Fault Duration (ms)**	**Voltage Recovery (% Un, time)**	**Comment**
Ireland	110, 220, 400	15	625	90% after 3s	
Great Britain	275, 400	same as conventional plant	same as conventional plant	same as conventional plant	Exemptions apply to PPM connected before 1/04/05
Spain	220, 400	20	500	80% after 1s; 95% after 15s	
Germany/ E.ON Netz	110, 200	45 (limit 1) 0 (limit 2)	150	70% after 150ms; Umin after 1.5s (limit 1) Umin after 1.5s (limit 2)	
Denmark (Energinet.dk)	132, 150, 400	25	100	75% after 750ms; Un after 10s	Wind farms connected at voltages above 110kV
USA / ERCOT	138, 345	0	150	90% after 1.75s	Wind farms connected after November 2008
Australia (Western Power)	66,132, 220, 330	same as conventional plant	same as conventional plant	same as conventional plant	Gen Plant >=10MW
New Zealand	50, 66, 110, 220	none	none	none	In consultation

[39] Based on information presented in Appendix A.

Table 4.5 Compliance Requirements for Conventional Generators

Compliance with Fault Ride Through Requirements – Conventional Generator					
Country TSO	**Connection application stage**	**Commissioning stage**	**Ongoing operation**	**Lifetime compliance**	**Comment**
Great Britain	Generator provides initial set of data, verified model in transfer function diagram form and self-certifying compliance statement form as required. Associated evidence of compliance with FRT reqs is not specified.	Generator provides additional information as required; SO reviews all info provided and if satisfied, grants consent to synchronisation (ION or FON). Post-ION compliance testing and witnessing unspecified.	Standard and detailed planning data to be submitted by the generator on annual basis. SO monitors the plant performance esp during frequency excursions and fault events. Any concerns will be discussed with the generator.	Generators are required to inform SO if their plant is about to become, or as soon as it become non-compliant. Generator status may change in accordance with the materiality of non-compliance.	Any known or potential non-compliance issues to be stated on the compliance statement form. ION is time limited and includes a list of any outstanding issues which must be resolved through testing or otherwise within defined timescales.
Spain	Stage 1: Generator provides data & PSS/E control block models; Stage 2: Generator submits compliance reports; TSO conducts verification studies.	Generator provides additional information and a test programme; no specific testing of FRT capability.	No documented requirements established. Generator performance monitored by control centre.	Unspecified	A non-compliant generator is not permitted to connect or commence commercial operation.

Compliance with Fault Ride Through Requirements – Conventional Generator (continued)					
Country TSO	**Connection application stage**	**Commissioning stage**	**Ongoing operation**	**Lifetime compliance**	**Comment**
Germany/ E.ON Netz	Generator provides initial set of data and information; TSO conducts FRT related studies only if the fault level is to be less or greater than six times the rating of the generator. Associated evidence of compliance with FRT reqs is not specified.	Generator is required to submit evidence of compliance including its behaviour during abnormal voltage deviations, no details on the specific tests or studies are available.	Unspecified	Unspecified	It is not clear who is responsible for monitoring and enforcing compliance during the lifetime of generating plant. .
Denmark (Energinet.dk)	Generator provides initial set of data and pre-commissioning compliance evidence required. The evidence consists of a FRT study report containing all required statements and documentation of the plant behaviour under grid faults. TSO conducts preliminary approval of the pre-commissioning information, and if satisfied, grants a temporary operating permit.	There are no specific FRT commissioning tests required. TSO approves the complete set of commissioning documentation, and if satisfied, grants final operating permit. Otherwise, the generator will need to cease operation.	Generator is required to continuously monitor compliance of its plant and report any changes.	Any change in plant characteristics or performance (including temporary changes for plants larger than 25MW) must be reported to the TSO immediately along with the updated documentation. Any modification to the generating plant requires the same pre- and commissioning process.	

Compliance with Fault Ride Through Requirements – Conventional Generator (continued)					
Country TSO	**Connection application stage**	**Commissioning stage**	**Ongoing operation**	**Lifetime compliance**	**Comment**
USA / ERCOT	Generator provides technical data to be used in modelling studies as required. No indication of specific FRT related studies to be performed by ERCOT.	Generator provides the commissioning and initial synchronisation checklists and data as required.	Generator is required to remain in compliance with ERCOT protocol and operating guide requirements. No information in relation to compliance monitoring and reporting.	Any equipment changes that decrease FRT capability of wind generating plants must be approved by ERCOT prior to implementation.	
Australia (Western Power)	Generator submits a full set of generation data and conducts studies to demonstrate compliance with the Technical Rules. TSO often performs its own studies to verify the results provided by the generator.	Comprehensive compliance testing but no specific FRT tests are required.	Generator should ensure compliance at all times and must provide ongoing verification of compliance. But the procedure for this is not clear.	Unspecified	Western Power require that compliance tests must only be performed after the machines have been certified compliant by a Chartered Professional Engineer with National Professional Engineers' Register standing, qualified in a relevant discipline.
New Zealand	Generator provides data for general TSO studies.- FRT is not assessed.	No specific FRT tests are required.	No procedure	No procedure	New requirements currently in consultation

Table 4.6 Compliance Requirements for Non-synchronous Generators[40]

Compliance with Fault Ride Through Requirements – Non-Synchronous Generator					
Country TSO	**Connection application stage**	**Commissioning stage**	**Ongoing operation**	**Lifetime compliance**	**Comment**
Great Britain	For type validated power park units, generator provides the correct Type Register reference for its Unit, if /as appropriate and confirms with SO that the Type Register information is appropriate and sufficient. Otherwise, generator must provide the full set of unit data and validated model of the Power Park Module.	_Type validated units:_ FRT compliance verified as per type validation evidence provided test environment was equivalent or more demanding than the actual power park location. _Non-type validated units:_ FRT compliance testing and verification as per guidance notes requirements. SO reviews all info provided & if satisfied, grants consent to synchronisation (ION or FON).	Standard and detailed planning data to be submitted by the generator on annual basis. SO monitors the plant performance esp during frequency excursions and fault events. Any concerns will be discussed with the generator as part of the normal and ongoing process.	Generators are required to inform SO if their plant is about to become, or as soon as it become non-compliant. Generator status may change in accordance with the materiality of non-compliance.	Type Register reference is not a guarantee of compliance of a Power Park Module; the suitability of the Type Register reference should be discussed with National Grid as part of the normal compliance process. The Power Park Module compliance tests can only be undertaken with at least 95% of the Power Park Units in service with full compliance capability being confirmed when all power park units are operational.

[40] Based on information presented in Appendix A.

Compliance with Fault Ride Through Requirements – Non-Synchronous Generator (continued)					
Country TSO	**Connection application stage**	**Commissioning stage**	**Ongoing operation**	**Lifetime compliance**	**Comment**
Spain	As conventional	As conventional Plus guide from the AEE (Spanish Wind Energy Association); Procedure for Verification, Validation and Certification of the Requirements of P.O.12.3 on the Response of Windfarms in the Event of Voltage Dips, Version 3, November 2007	Centralised control centre dedicated to controllable renewables continuously monitors behaviour of renewable generation; it also conducts real time simulations of faults in order to predict generators response to voltage dips and identify potential poor FRT performing generators that may need replacing.	Unspecified	A non-compliant generator is not permitted to connect or commence commercial operation. In 2006, non-compliant wind generators were given a limited time period to adapt / ensure compliance with the new requirements.
Germany/ E.ON Netz	Generator provides initial set of data and information; TSO conducts FRT related studies only if the fault level is to be less or greater than six times the rating of the generator. Associated evidence of compliance with FRT reqs is not specified.	Generator is required to submit evidence of compliance including its behaviour during voltage deviations. The plant certification could form part of the compliance evidence. No details on the specific FRT tests or studies required.	Unspecified	Unspecified	It is not clear who is responsible for monitoring and enforcing compliance during the lifetime of generator.

Compliance with Fault Ride Through Requirements – Non-Synchronous Generator (continued)					
Country TSO	**Connection application stage**	**Commissioning stage**	**Ongoing operation**	**Lifetime compliance**	**Comment**
Denmark (Energinet.dk)	Generator provides a full data set and model of the wind farm. TSO conducts its own studies and validates the wind farm model. Both individual wind turbines and wind farm projects are nowadays expected to be type certified as per Danish certification scheme.	Upon connection, the generator provides compliance documentation (eg wind turbine tests and wind farm model). A commissioning test verifying compliance with all the regulations requirements is arranged. It is not clear whether/what FRT compliance tests (if any) would need to be performed.	Unspecified	Any change to or replacement of existing wind units is treated as a connection of new units requiring compliance with all technical requirements.	
USA / ERCOT	Generator provides technical data to be used in modelling studies as required. No indication of specific FRT related studies to be performed by the generator or ERCOT.	Generator provides the commissioning and initial synchronisation checklists and data as required.	As conventional plus: If a wind farm disconnects within the boundaries of the FRTrequirement, the generator and transmission service provider are required to investigate and report to ERCOT on the cause of the trip, mitigation plan and timeline.	Any equipment changes that decrease FRT capability of wind generating plants must be approved by ERCOT prior to implementation.	Wind farms with the connection agreement signed after 1 November 2008 were required to provide a status of compliance, including existing FRT capabilities in order to dentify a potential need for retrofitting.

Compliance with Fault Ride Through Requirements – Non-Synchronous Generator (continued)					
Country TSO	**Connection application stage**	**Commissioning stage**	**Ongoing operation**	**Lifetime compliance**	**Comment**
Australia (Western Power)	As conventional	As conventional	As conventional	As conventional	
New Zealand	As conventional	As conventional	As conventional	As conventional	Under consultation

APPENDIX A - TREATMENT OF NON-SYNCHRONOUS GENERATION

A.1 Great Britain

Existing FRT requirements

The national Grid Code changes to account for new generation technologies were introduced on 1 June 2005 following a lengthy consultation process during which risk and operating costs under a high penetration of new generation technology scenarios have been examined. The change proposals have affected several areas to include fault ride through, power/frequency characteristics, frequency control, ramp rates, reactive range and voltage control and negative phase sequences.

Prior to the development of new generation technologies, in particular wind generation, the (clusters) of non-synchronous generating units in the order of tens of MW were normally connected to distribution networks. The loss of few tens of MW of embedded generation in a local distribution network due to a distribution network fault or nearby transmission system fault would not normally have a material impact on the transmission system. Accordingly, at the time there was no need for generation to be specified to have FRT capability although, with large volumes of embedded generation, FRT could become an issue where a major transmission system fault causes a significant voltage depression in a number of distribution networks. However, as the penetration of non-synchronous generation has been increasing in both transmission and distribution networks, the requirement for FRT has become a necessity to ensure system stability and security of supply as the loss of large amount of wind generation due to inability of the affected generation to ride through a fault that may have also caused the loss of 1320MW of conventional generation clearly has a material impact on system stability and security of supply.

Consequently, the above mentioned grid code changes in relation to FRT have introduced a set of FRT provisions for both synchronous (e.g. conventional) generation and non-synchronous generation (e.g. DC converters and Power Park Modules - a collection of non-synchronous generating units with intermittent power sources such as wind turbine generators). The onshore Power Park Modules are required to meet the FRT requirements outlined in Section 3.1.3, i.e. to have the same FRT capability as conventional generation. Offshore Power Park Modules are required to meet either the requirements outlined in Section 3.1.3 or an alternative set of FRT requirements as defined in the CC 6.3.15.2 of the Grid Code.

However, the new requirements for onshore and offshore Power Park Modules do take into consideration the wind farm operating conditions (e.g. effect of wind speed on wind power output), and possible limitations of some older / existing wind farms particularly in Scotland with respect to FRT capability and overall system stability. They also clearly differentiate between the requirements intended for existing plant and the requirements for plant installed after the 1 April 2005. As a result, the additional set of requirements and/or exemptions applies as follows:

- In the case of a Power Park Module (comprising of wind-turbine generator units), the above requirements do not apply when the Power Park Module is operating at less than 5% of its Rated MW or during very high wind speed conditions when more than 50% of the wind turbine generator units in a power park have been shut down or disconnected under an emergency shutdown sequence to protect users plant and apparatus.
- A non-synchronous generating unit or Power Park Module is required to withstand without tripping, the negative phase sequence loading incurred by clearance of a close-up phase-to-phase fault by system back up protection on the GB transmission system operating at supergrid voltage.
- Power Park Modules in Scotland connected at 132kV and above with a completion date prior to 2005 may be exempt from certain ride through requirements. For details, see CC.6.3.15.3 (iii) of the Grid Code.
- To avoid unwanted island operation, non-synchronous generating units in Scotland or Power Park Modules in Scotland should be tripped for the following conditions:
  - Frequency above 52Hz for more than 2 seconds (e.g. max trip time);
  - Frequency below 47Hz for more than 2 seconds (e.g. max trip time);
  - Voltage at the connection point or user system entry point below 80% for more than 2 seconds; and
  - Voltage at the connection point or user system entry point above 120% for more than 1 second.

Compliance of non-synchronous generators

Compliance assurance for non-synchronous generation is described in detail in the guidance notes for Power Park Modules[41]. The compliance assurance process throughout the lifetime of the Power Park Module follows a very similar general procedure as that for conventional generation described in Section 3.1.4. However, the requirements in relation to information

[41] Guidance Notes for Power Park Developers, National Grid, September 2008.

provision and compliance verification at the connection and commissioning stages differ slightly in order to reflect the design features of a typical Power Park Module.

Power Park Modules are generally comprised of a large number of identical Power Park Units with the performance of a specific Power Park Unit type being normally reasonably constant from unit to unit regardless of the site where they are installed. National Grid therefore allows single registration of various aspects of the unit performance and associated data once in a Type Register as illustrated in Figure A.1.1. In this process, the information may only come from the manufacturer although a developer may be involved by providing site test opportunities.

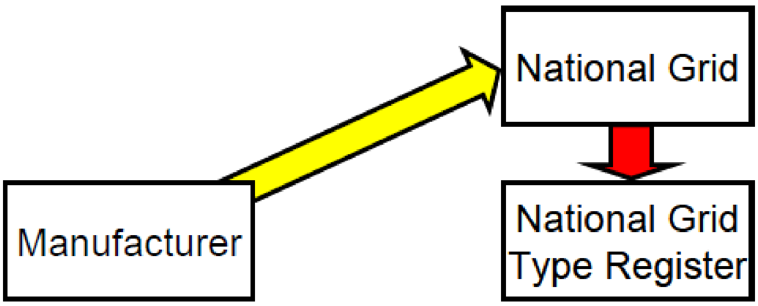

Figure A1.1 Type Registration

Each wind developer can, where appropriate, reference information held in the National Grid Type Register, substituting information that they are required to submit before connecting to the GB transmission system. Wind developers are supposed to obtain the correct reference from the manufacturer. If no relevant data or insufficient data is held in the Type Register then the data must be provided in full by the developer.

The following areas have been deemed suitable for Type Registration by National Grid:

(a) Fault Ride Through capability

(b) Reactive Capability

(c) Voltage Control

(d) Frequency Control

(e) Power Park Module mathematical model

(f) Fault in-feed contribution.

Items (a), (b), (c), (d) correspond to actual Power Park Unit tests. Items (e) and (f) correspond to simulation studies. The manufacturer may chose to apply for Type Registration in one or more of the above mentioned areas. A series of tests and data submissions will be developed to demonstrate the performance characteristics of a single Power Park Unit. Details of these tests and submissions are to be agreed between the Power Park Unit manufacturer and National Grid with National Grid having the right to witness some or all of these tests. In each case the manufacturer should submit a detailed report to National Grid for approval and consequent submission into the Type Register.

Where a non-synchronous generator provides the Type Register reference for its Power Park Unit, there is no need for a mathematical model (except for site specific parameters) that represents the entire Power Park Module. In addition, National Grid may not require some simulation studies (e.g. FRT studies) and may agree to a reduced commissioning programme if a Power Park Unit has been Type Registered for one or more of the following (i) reactive capability (ii) voltage control or (iii) frequency control.

Using Type Registered data does not guarantee Grid Code compliance for a Power Park Module, but does indicate that the Power Park Unit is capable of achieving Grid Code compliance in the appropriate area. Limited tests may be required to confirm that the performance of the Power Park Module aligns with the data held by National Grid in the Type Register.

Simulation studies are required where it is impractical to demonstrate capability through testing as the effects on other system Users would be unacceptable. The simulations must be based on validated models supplied to National Grid.

Where no factory type test validation information is available for a Power Park Unit model, it is the responsibility of the Generator to ensure that the response of the Power Park Unit model is validated against the criteria required in the Unit Tests. This should be done by simulating the tests using the validated model.

Prior to synchronisation of the first Power Park Unit i.e. at least 1 month in advance of the Interim Operational Notification, the non-synchronous generator must provide National Grid with a schedule of commissioning tests and associated procedures for each Power Park Module. These should indicate those tests which, to generator knowledge, may have an impact on the GB Transmission System or other users. National Grid will use this information to identify those tests, if any, which may have an adverse impact on the GB Transmission System, or to any equipment belonging to other Users of the GB Transmission System. In particular, National Grid will require detailed information on: MVAr Capability Tests, Voltage Control Tests, Frequency Response Tests, Fault Ride Through Tests and model validation tests. Some tests may also be required following synchronisation; any such activity should be coordinated with National Grid and relevant TO/DNO.

Compliance with FRT requirements

Demonstrating fault ride through and power recovery capability at site by applying supergrid faults is not practical and other evidence mechanisms are needed. National Grid has identified three levels for demonstration of compliance at the connection and commissioning stages. The levels take into account any type validation status of Power Park Units and size of Power Park Module.

The first two levels assume that Power Park Units have previously demonstrated a level of ride through capability in a suitable test environment (type validated). Compliance is verified if the unit capability has previously demonstrated capability in a controlled environment and that simulation study evidence shows the test environment to be equivalent or more demanding than the actual Power Park location.

The third level applies to non-type validated units where compliance is tested and verified on a case by case basis. Further details of each level and a description of fault requirements can be found in Sections 4 and 5 of the `Guidance Notes for Power Park Developers'.

As indicated above, the generator which intends to use Type Registered data needs to contact National Grid early in the compliance process to determine if the information held in the Type Register is appropriate and sufficient in each case. National Grid would not require Fault Ride Through simulation studies to be conducted provided that for each type and duration of fault the expected minimum retained voltage is greater than the corresponding minimum voltage achieved and successfully ridden through in the Type Register Fault Ride Through report produced by the manufacturer.

It is worth pointing out that a Type Register reference is not a guarantee of compliance of a Power Park Module; different Power Park Modules may be comprised of the same Power Park Unit type but use different sources of dynamic reactive power resulting in differences in performance. For that reason, the suitability of the Type Register reference should be discussed with National Grid as part of the normal compliance process.

The Power Park Module compliance tests can only be undertaken with at least 95% of the Power Park Units in service with full compliance capability being confirmed when all Power Park Units are operational. In some cases the compliance tests may be approved at reduced capacity provided National Grid are satisfied that the Power Park Module capability is sufficiently supported by generic type validation tests and site design data.

A.2 Spain

Existing FRT requirements

Due to the increasing wind power integration in the Iberian system, characterised by limited interconnection capacities with neighbouring countries and the features of the existing wind power plants (without FRT), it was necessary to review the wind energy penetration that is technically permissible in the Spanish power system in peak and off-peak periods.

The review resulted in the publication of P.O.12.3 "Requisitos de respuesta frente a huecos de tensión de las instalaciones eólicas" issued on October 4th, 2006[42]. It contains the wind farm generator requirements necessary to secure a high wind power penetration in the Iberian system whilst ensuring security and quality of supply. The P.O.12.3 requirements are related to FRT capability, shown in Figure A2.1, and injection of reactive power during faults to support network voltage, shown in Figure A2.2.

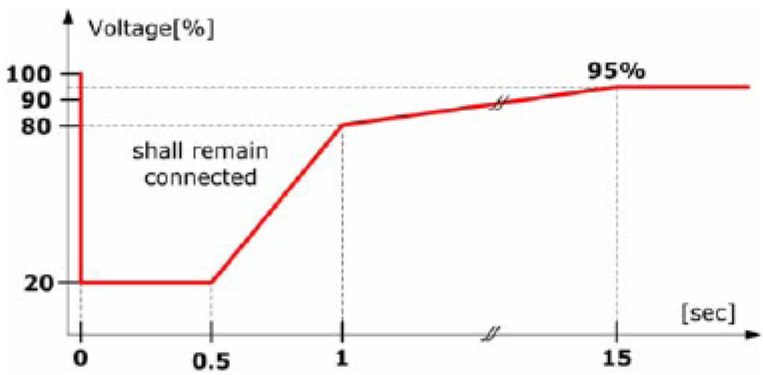

Figure A2.1: Fault ride through requirement of P.O.12.3 for wind generators.

As well as applying to new wind generator connections the P.O.12.3 requirements also apply retrospectively to existing wind generators. Existing generators have been given a transition period in which to modify their capability but this is currently an area of strong debate in Spain.

A wind farm is required to provide the electrical power system with voltage support at the point of common coupling (PCC) with the maximum possible current during the fault and during voltage recovery according to the curve presented in Figure A2.2.

[42] http://www.ree.es/operacion/pdf/po/PO_resol_12.3_Respuesta_huecos_eolica.pdf

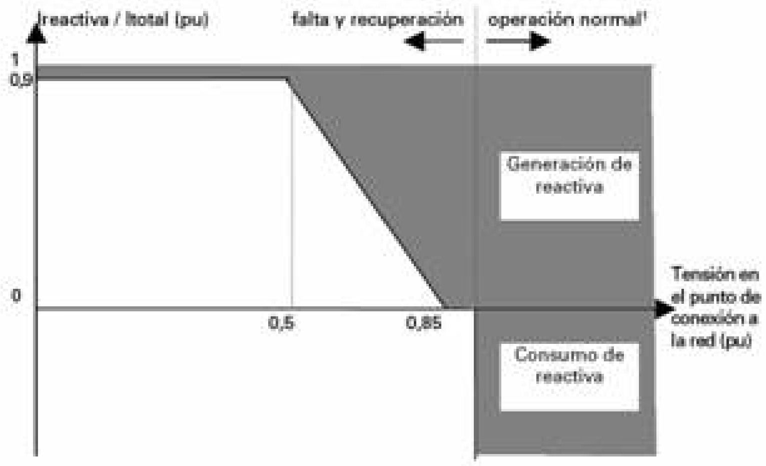

Figure A2.2: Wind generator reactive power requirements to support voltage recovery

Reactive and active power requirements for a symmetrical network fault are:

- During the fault and recovery period the wind generator will not consume reactive power beyond the following limits;
  - A maximum period of 150ms following fault inception the reactive power consumption will be no greater then 60% rated power in every cycle.
  - A maximum period of 150ms following fault elimination the reactive power consumption will be no greater then 60% rated power, and reactive current will not exceed 1.5 times full rated current for each cycle.
- During the fault and recovery period the wind generator will not consume active power beyond the following limits;
  - A maximum period of 150ms following fault inception and elimination.
  - A maximum value of 10% of rated power during the remainder of the fault duration.

Reactive and active power requirements for a asymmetrical network fault are:

- During the fault and recovery period the wind generator will not consume reactive power beyond the following limits;
  - A maximum period of 150ms following fault inception and elimination.
  - A maximum value of 40% of rated power during each cycle of the remainder of the fault duration.
- During the fault and recovery period the wind generator will not consume active power beyond the following limits;

- During the remaining fault duration the active power consumption is no greater than 40% of rated power for a 100ms period with no greater than 30% rated power during any cycle.

Compliance assurance

Compliance assurance for non-synchronous generation from the connection application phase follows the same procedure as that for conventional generation with the exception that technical requirements are defined in P.O.12.3.

In the case of validating compliance for wind generators a document detailing the procedure for measuring and assessing the response of wind farms in the event of voltage dips has been produced by the AEE (Spanish Wind Energy Association); Procedure for Verification, Validation and Certification of the Requirements of P.O.12.3 on the Response of Windfarms in the Event of Voltage Dips, Version 3, November 2007[43]. However, this is written as a guidance note to wind generators and is not part of the Grid Code.

When P.O.12.3 was introduced in 2006 there were many wind generators in Spain that became non-compliant. These non-compliant generators were given a transition period for adaption to the new requirements, at their own cost. Any generators that were unable to technically adapt had to provide valid reasons to REE in writing and those unwilling to adapt lost the financial incentive of the feed-in tariff.

At present the technical requirements of P.O.12.2 are under review (which will also be applicable to non-synchronous generators) and could potentially mean that installations that adopted the 2006 requirements may become non-compliant. The generators are not willing to pay to adapt again, so the adoption of the FRT requirements described is causing great discussion. There is no agreement on who must pay for the adaptation of the generators.

Spain is unique in having a centralised control centre (CECRE) dedicated to controllable renewables. CECRE has complete information on the control schemes of all renewable generators and is dedicated to monitoring their behaviour. A non-compliance will be almost immediately detected, even before a problem in the grid happens, since CECRE continuously runs real time simulations of faults and analyses the response of independent generators to voltage dips. It then ranks generators according to their performance and instigates appropriate mitigation measures.

[43] http://www.aeeolica.es/doc/privado/pvvc_v3_english.pdf

A.3 Germany

Existing FRT requirements

The fault ride through requirements for wind and other unconventional generation (i.e. Type 2 generating plant) are discussed below. It is worth noting that smaller wind farms or single wind turbines being connected to the distribution system (i.e. medium voltage system) are currently not covered by the connection conditions of the German TSOs.

The following minimum FRT requirements apply to Type 2 generating plants:

- In the event of faults in the grid outside the protection range for the generating plant, there must be no plant disconnection from the grid. Short circuit current must be fed into the grid during the fault duration. Depending of the generator technology used (e.g. asynchronous generators or frequency converters) the short circuit current contribution must be agreed with E.ON on a case by case basis.

- If the voltage at the grid connection point drops and remains at a value at or below 85% of the nominal voltage (380/220/110 kV e.g. 110 kV x 0.85 = 93.5kV) with the generator operating in its under-excited mode (e.g. reactive power direction to the connectee), the generating plant must be disconnected from the grid after a time delay of 0.5 seconds. The disconnection must be made at the generator circuit breaker.

- If the voltage on the low voltage side of each individual generator transformer falls and remains at or below 80% of the lower value of the voltage band (e.g. 690 V x 0.95 x 0.8 = 525 V) based on a resetting ratio of 0.98, one quarter of the generators must disconnect themselves from the grid after 1.5s, 1.8s, 2.1 s and 2.4 s respectively. Different disconnection times can be agreed in individual cases.

- If the voltage on the low voltage side of each individual transformer rises and remains at over 120% of the upper value of the voltage band (e.g. 690 V x 1.05 x1.2 = 870 V) based on a resetting ratio of 1.02, the affected generator must disconnect itself from the grid after a minimum duration of 100 ms. Different disconnection time can be agreed in individual cases.

In addition, it is recommended to disconnect affected generators without any time delay in the event of frequency deviation below 47.5Hz or above 51.5 Hz.

Following disconnection of a generating plant from the grid due to an over frequency, underfrequency, undervoltage, overvoltage or after the end of isolated operation, automatic synchronisation of the individual generators with the grid is only allowed if the voltage at the grid connection point is greater than 105kV in the 110 kV grid, or 210 kV in the 220 kV grid or 370 kV in the 380 kV grid. The voltage values refer to the lowest value of the three line-to-line grid voltages. After generator disconnection, the increase in the generator active power output must not exceed the maximum gradient of 10% of the grid connection capacity per minute.

Figure A3.1 shows the voltage limit curve at the grid connection point for Type 2 generating plants.

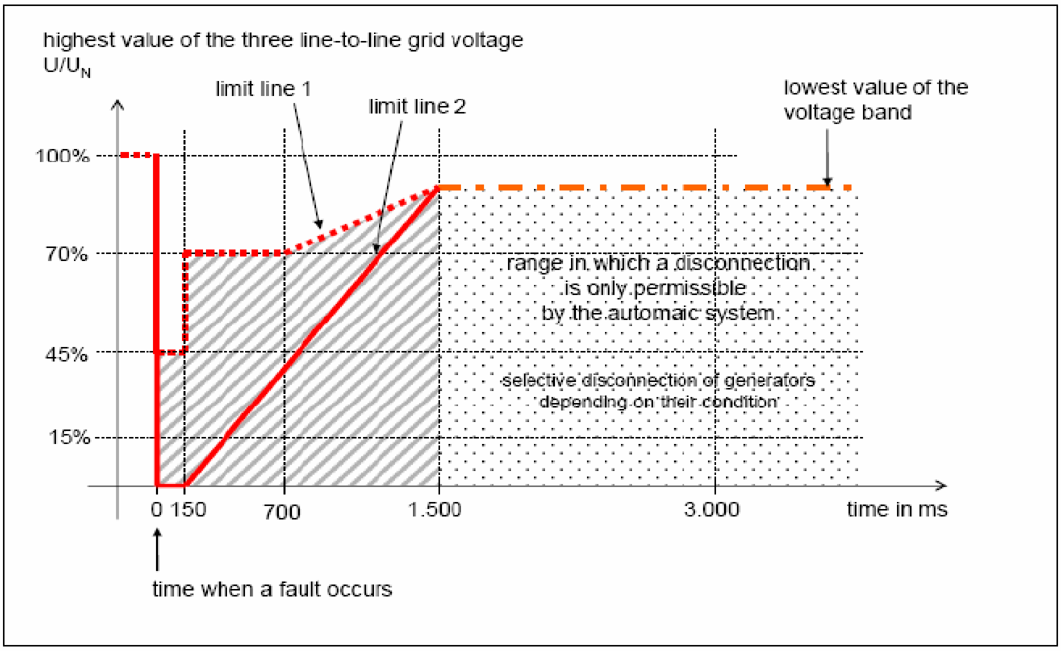

Figure A3.1 Voltage duration profile for Type 2 generating plant

Three-phase short circuits or symmetrical fault related voltage dips above the limit line 1 in Figure A3.1 must not lead to instability or disconnection of the generating plant from the grid.

The following requirements apply within the shaded area above the limit line 2 in Figure A3.1:

- Type 2 generating plants should withstand the fault without disconnection from the grid. If, due to the generating plant connection design, a generating plant cannot fulfil this requirement, it is permitted (with agreement from E.ON) to alter the limit line while at the same time reducing the resynchronisation time and ensuring a minimum reactive power infeed during the fault. The reactive power infeed and resynchronisation must take place so that the generating plant meets, in a suitable way, the respective requirements of the grid at the grid connection point.

- If during a fault, the individual generator becomes unstable or the generator protection responds, a brief disconnection of the generating plant (KTE) from the grid is allowed with agreement from E.ON. A resynchronisation of generating plant must not take longer than 2 seconds and active power output must increase to the original value with a gradient of at least 10% of the generator rated active output per second.

A KTE from the grid is allowed below limit line 2 in Figure A3.1. In this case, a resynchronisation time of more than 2 seconds and an active power increase of less than 10% of the rated power per second are allowed in exceptional cases with agreement from E.ON.

For all generating plants that do not disconnect from the grid during the fault the active power output must be continued immediately after fault clearance and increased to the original value with a gradient of at least 20% of the rated power per second.

The generating plants must support the grid voltage with additional reactive current during a voltage dip. In the event of a voltage dip of more than 10% of the effective value of the generator voltage, the voltage control must be provided as shown in Figure A3.2. The voltage control must take place within 20 ms after fault recognition by providing a reactive current on the low voltage side of the generator transformer amounting to at least 2% of the rated current for each percent of the voltage dip. A reactive power output of at least 100% of the rating current should be possible if necessary.

Upon voltage return to within the deadband, the voltage support must be maintained for further 500 ms in accordance with the specified characteristic. The transient balancing process following the voltage return must be completed within 300 ms.

In cases where generating plants are electrically distant from the grid connection point, resulting in the voltage support being ineffective, E.ON requires measurement of the voltage dip at the grid connection point and provision of the voltage support as a function of the measured value.

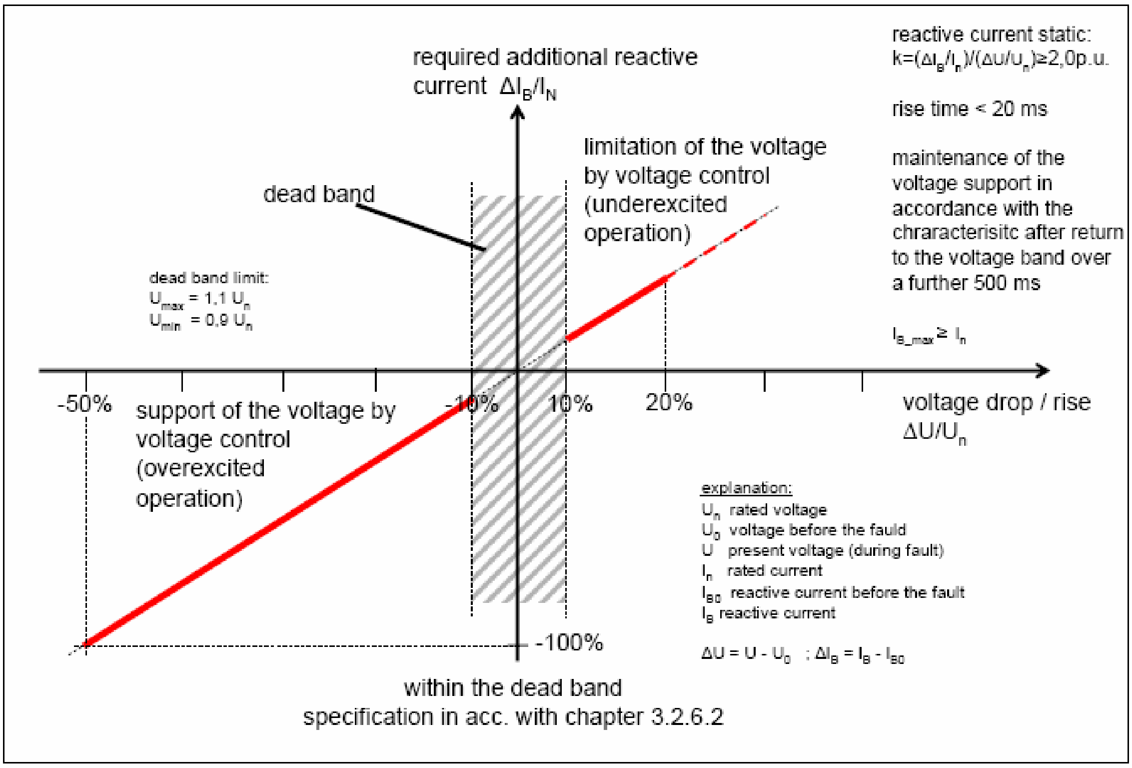

Figure A3.2 Voltage support during grid faults

Compliance assurance

Compliance assurance for non-synchronous generation follows the same procedure as that for conventional generation. For details, see Section 3.3.4.

A.4 Denmark

Existing FRT requirements

The requirements for connection of wind farms to the Danish transmission system have been in existence since 1999. They have been under continuous review and the current requirements for connection of wind farms at voltages above 100kV are set out in the Eltra & Elkraft Technical Regulations 3.2.5 issued in November 2004. These requirements apply to wind farm connections made after 1 December 2004. A new version of wind farm connection requirements has been developed but is not yet available in English; a translated version is expected to be available by the end of 2010.

Previously only large conventional power stations were responsible for control and stability of the Danish power system. With an increasing proportion of electricity being generated from renewable sources, revised requirements and obligations in terms of provision of system operation and security related services have been placed upon wind farms. Wind farms are now required to provide a similar level of functional performance as conventional generating plant whilst taking into account the performance capabilities of the current wind turbine generator designs and overall wind generation technology development.

Technical regulations 3.2.5 define fault conditions under which the wind farm (and associated compensation) is not allowed to trip. The ride through conditions for different grid faults is shown in Table A4.1.

Three-phase short circuit	Short circuit in 100 ms
Two-phase short circuit with/without earth contact	Short circuit in 100 ms followed by a new short circuit 300…500 ms later, also with a duration of 100 ms
Single-phase short circuit to earth	Single-phase earth fault 300…500 ms later, also with a duration of 100 ms

Table A4.1. Faults under which a wind turbine generator must not trip

A wind farm should have sufficient capability to meet the above requirements in the event of the following independent fault scenarios:

- At least two single-phase earth faults within two minutes;
- At least two two-phase short circuits within two minutes; and
- At least two three-phase short circuits within two minutes.

Additionally, there should be sufficient energy reserves (emergency power, hydraulics and pneumatics) for the following three independent fault sequences:

- At least six single-phase earth faults with five minute intervals;
- At least six two-phase short circuits with five minute intervals; and
- At least six three-phase short circuits with five minute intervals.

Furthermore, the wind farm shall be able to withstand the impacts from asymmetrical faults in the grid where unsuccessful automatic reclosing takes place without necessitating disconnection of wind turbines in the wind farm.

The required behaviour of wind farms during symmetrical three phase faults and asymmetric faults accompanied with unsuccessful reclosing is described below.

(a) Behaviour during symmetrical three-phase grid fault

In order to demonstrate the behaviour of the wind farm in the case of a three-phase fault with a slowly recovering voltage, Technical Regulations 3.2.5 require that a turbine model simulation is undertaken with the voltage profile shown in Figure A4.1[44].

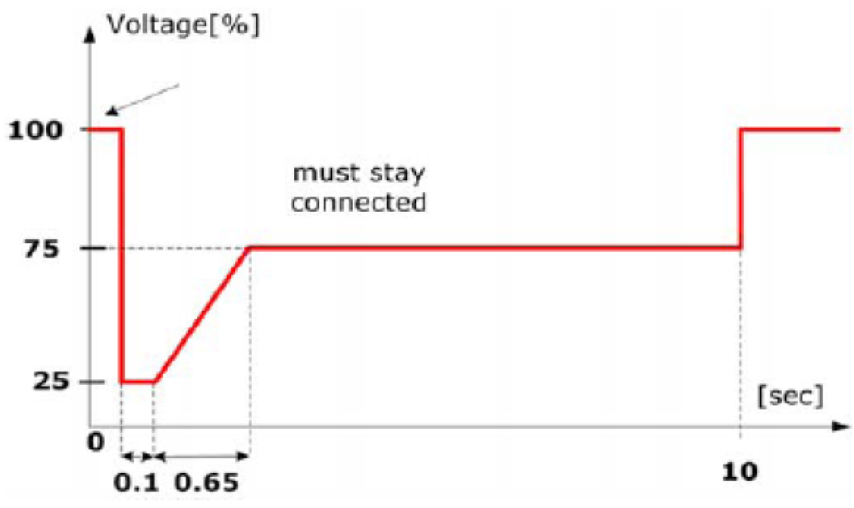

Figure A4.1 Voltage-Duration profile during a 3-phase symmetric fault

For modelling purposes, the power system is required to be represented by a Thevenin equivalent along with the set of fault and operating conditions that would need simulating as described in the regulations.

[44] Mapping of grid faults and grid codes, Technical University of Denmark, July 2007.

In addition to riding through the three phase fault, the wind farm is expected to produce the rated power no later than 10 seconds after the voltage has recovered to above 0.9pu. During the voltage dip the active power shall meet the following condition:

$$P_{current} \geq K_p \times P_{t=0} \times (U_{current} / U_{t=0})^2$$

where:

$P_{current}$ - current active power measured at the connection point

$P_{t=0}$ - power measured at the connection point immediately before the voltage dip

$U_{t=0}$ - voltage at the connection point immediately before the voltage dip

$U_{current}$ - current voltage measured at the connection point

K_p = 0.4 - reduction factor considering any voltage dips to the generator terminals.

Required exchange of reactive power with the grid is to resume no later than 6 seconds after the voltage has recovered to above 0.9pu. During the voltage dip, the maximum reactive current (measured at the point after the Thevenin impedance) that can be taken by the wind farm should not exceed the nominal current of the wind farm.

During the voltage dip, the wind farm is required to provide maximum voltage support so as to help re-establish normal voltage levels as soon as possible.

(b) Behaviour following asymmetric grid faults and unsuccessful reclosure

The wind turbine generator is required to withstand the impacts from the following asymmetric faults in the grid without disconnection:

- a two phase line fault with unsuccessful reclosure;
- a single-phase fault on a line in the transmission grid with unsuccessful reclosure.

The wind generator behaviour during these two fault conditions should meet the voltage profiles shown in Figure A4.2.

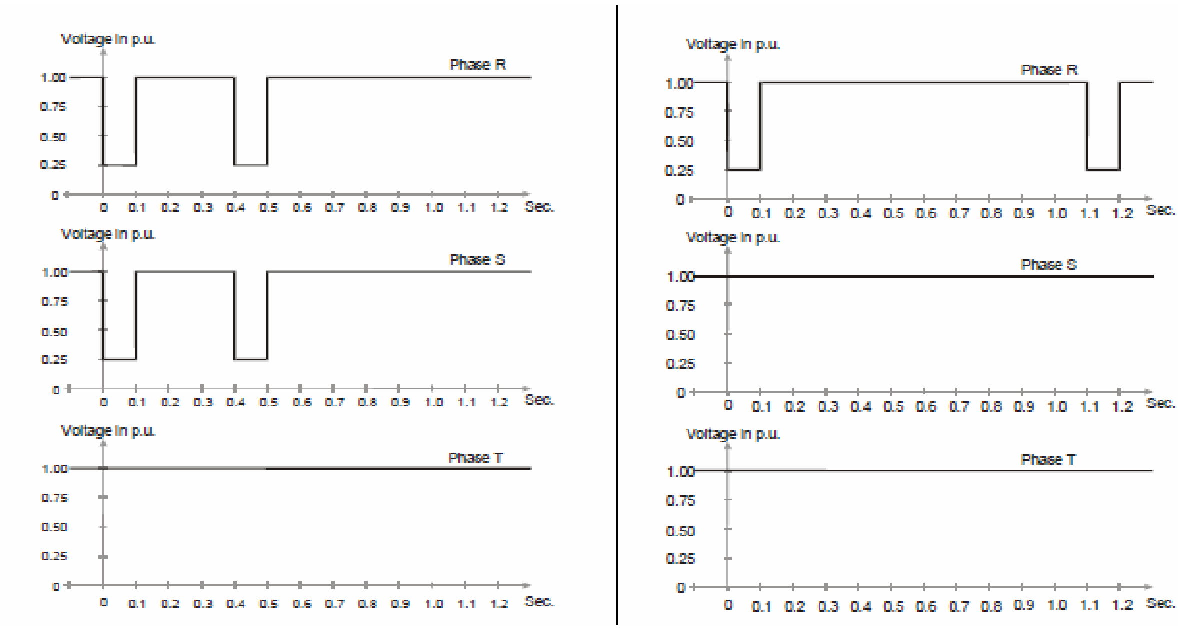

Figure A4.2 Voltage-duration profiles during a 2-ph fault (left) and 1-ph fault (right)

In addition, the wind farm is required to:

- withstand the thermal impacts at repetition of the turbine test after two minutes;
- withstand the thermal impacts at repetitions of the asymmetric faults described above after two minutes;
- have sufficient energy reserves for six repetitions of the turbine test at five minute intervals;

have sufficient energy reserves for six repetitions of asymmetric faults described above at five-minute intervals.

Compliance assurance

Similarly to the commissioning process of thermal plants, it is the responsibility of the wind developer to ensure that its wind farm complies with the technical requirements and to provide all the necessary data and evidence of compliance to the regional grid company and the system operator.

Replacement of and/or radical changes to existing types of wind generators will be treated as new units which should comply with the current requirements.

In Denmark, the wind turbines are expected to be type tested in accordance with Order no 270 of the Danish Energy Authority[45]. The approval of wind turbines has been performed since 1979 with a new certification scheme based on IEC WT01 being introduced in January 2005. The purpose of the new certification scheme was to have a Danish certification system based on international standards and to include both type certification and project certification. Specific Danish requirements have been identified and added to the certification rules described in IEC WT01.

Upon connection of the wind farm to the transmission network, the wind developer is required to provide compliance documentation to the regional grid company as described in Technical Regulations 3.2.5. The documentation would include the wind turbine tests and a complete model of the wind farm. A commissioning test verifying compliance with all the regulations requirements would need to be arranged jointly by the regional grid company, the system operator and the wind developer. Upon approval of the submitted documentation, the system operator would grant the developer permission to operate.

As mentioned in Section 3.4.4, turbine simulation studies would need to be performed In order to verify that the wind farm complies with the FRT requirements illustrated in Figures 3.4.4 and 3.4.5. All wind turbine technologies that may exist within the wind farm should undergo such modelling. The worst case scenario should be modelled and assumes a simulation of wind farm behaviour under a three phase fault. The simulation results that include the current, voltage and real/reactive power behaviour as well as details related to the simulation study and simulation tool themselves should be submitted to the system operator for approval. The system operator requires a full data set and model of the wind farm so as to be able to conduct its own studies and validate the wind farm model.

[45] Order no 270: Order on type testing and certification of wind turbines, 2 May 1991.

A.5 USA (ERCOT)

Existing FRT requirements

Prior to November 2008 there was no FRT requirement for wind generating plants connected to ERCOT's network even though many wind developers had voluntarily installed FRT capability as described in FERC Order 661 and Order 661-A at the time.

The newly introduced FRT requirements for wind generating plants are now embodied in ERCOT Operating Guide, Section 3. These requirements are known as voltage ride through (VRT)[46] requirements in the USA and state:

- Wind-powered generating resources (WGR) are required to set generator voltage relays to remain in-service during all transmission faults (no more than nine cycles) in accordance with Figure A5.1 below. Faults on individual phases with delayed clearing (zone 2) may result in phase voltages outside this boundary but if the phase voltages remain inside this boundary then generator voltage relays are required to be set to remain connected and recover within the voltage recovery boundary of Figure A5.1.
- WGR voltage relays shall be set to remain interconnected during three-phase faults on the transmission system for a voltage level as low as zero volts with a duration of nine cycles as measured at the point of interconnection as shown in Figure A5.1 unless a shorter clearing time requirement for a three-phase fault specific to the generating plant point of interconnection is determined by and documented by the transmission provider in conjunction with the standard generation interconnection agreement. This requirement does not apply to faults that would occur between the generator terminals and the transmission voltage side of the generation step-up transformer or when clearing the fault effectively disconnects the generator from the system.
- WGRs may be tripped after the fault period if this action is intended as part of a special protection system.
- WGRs may meet the VRT requirements of Figure A5.1 by the performance of the generators or by installing additional equipment (e.g., Static VAr Compensator) within the generating plant or by a combination of generator performance and additional equipment.
- WGRs that have had over 50 seconds cumulative operation over the life of the WGR below 10% of nominal voltage at the point of interconnection shall be allowed, with ERCOT's approval, to set generator voltage relays to provide sufficient protection to the

[46] "Voltage Ride-Through" is defined as the ability of a generating plant to remain connected to the transmission system for specified high voltage and low voltage conditions.

WGR to comply with warranty requirements and to retain the expected life of the resource.

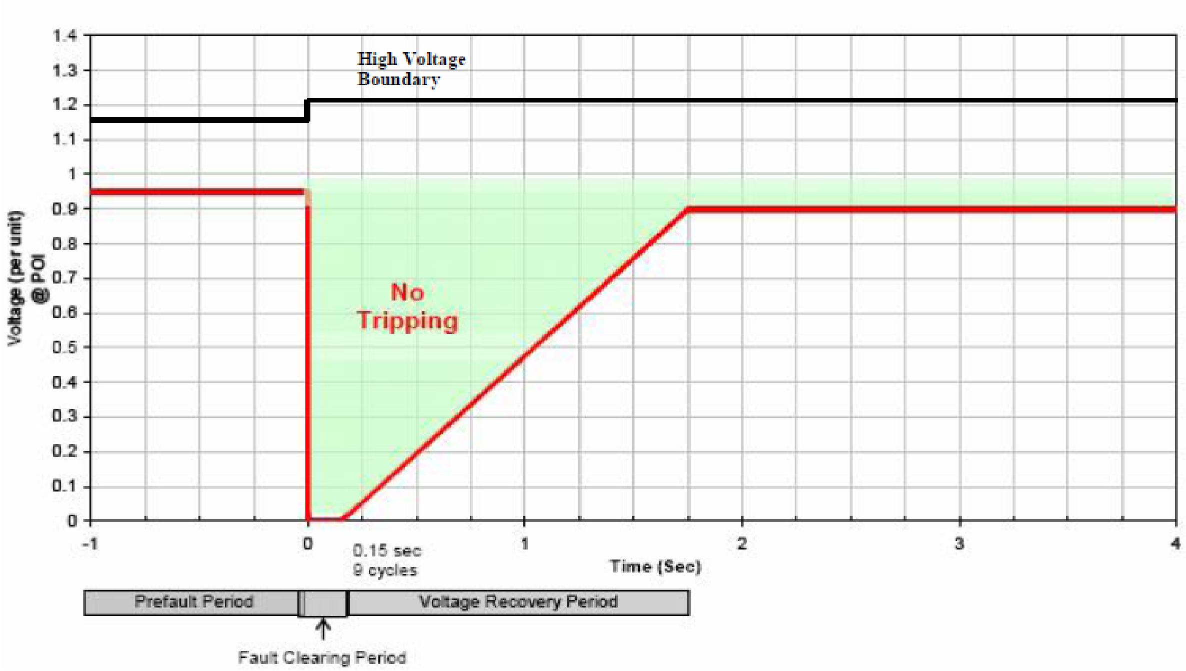

Figure A5.1. Voltage Ride-Through Boundaries for Wind-powered Generation Resources

The above requirements apply to:

- Existing individual WGRs that are replaced;
- WGRs with a connection agreement signed after 1 November 2008.
- Existing individual WGRs that meet the requirements of Figure A5.1 on 1 November 2008 are required to continue to meet the requirements of Figure A5.1.

WGRs that are part of a connection agreement signed prior to 1 November 2008 were asked to provide information requested by ERCOT, including existing WGR FRT capabilities, for a study to evaluate the need for additional protective relaying and FRT requirements applicable to some or all such WGRs. The results of this study conducted using ERCOT's 2009-2010 transmission system by an independent qualified organisation were expected by June 2010. If the results of the study demonstrate the need for retrofitting of some of the pre-November 2008 wind generating units, the Operating Guide will be revised accordingly and the required retrofits are expected to be installed within eighteen months after the effective date of the revised Operating Guide.

Compliance assurance

Connection of new generating plant to the ERCOT transmission grid is required to be in accordance with the ERCOT Standard connection agreement and procedures. The commissioning and initial synchronisation checklists have to be submitted to ERCOT confirming compliance with ERCOT Protocols and Operating Guide[47].

The wind generators are required to provide ERCOT with the operating characteristics of any generating unit's equipment protective relay system or controls that may respond to temporary excursions in voltage with actions that could lead to tripping of the generating unit within thirty days of ERCOT's request.

If, due to a system disturbance, a wind generating plant disconnects within the boundaries of the FRT requirement of Figure A5.1, then the generator and transmission service provider are required to investigate and report to ERCOT on the cause of the plant trip identifying a reasonable mitigation plan and timeline.

WGRs with the connection agreement signed after 1 November 2008 were required to provide a status of compliance to ERCOT System Planning by 1 July 2009.

Any equipment changes that may affect the reactive capability of an operating generating unit should be reported to ERCOT and the Transmission Service Provider within sixty days prior to implementation. Changes that decrease the reactive capability of the generating unit below the required level and changes that decrease the Voltage Ride-Through (VRT) capability of the plant must be approved by ERCOT prior to implementation.

[47] ERCOT New Generator Commissioning Checklist, July 2009.

A.6 Australia (Western Power)

Existing FRT requirements

Non-synchronous generators must comply with the same requirements as synchronous but with some additional criteria, largely based on the deficiencies of the early induction generator technology. The additional requirements from clause 3.3.3.3 of the Technical Code, reproduced below, are;

(f) **Post-Fault *Reactive Power* of a *Power Station* with Non-*Synchronous Generating Units***

> After fault clearing, the *power station* in which a non-*synchronous generating unit* is located must not absorb *reactive power* from the *transmission system* or the *distribution system*. Any pre-fault absorption of *reactive power* has to be terminated within 200 ms after clearing of the fault. The absorption is permitted to recommence, if required by the applicable *voltage* control strategy, after the post-fault *voltages* stabilize for at least 60 seconds at an above nominal value.

The above requirement is intended to mitigate undervoltage situations where a generator is potentially exacerbating the problem.

(g) **Post Fault *Voltage* Control of a *Connection Point***:

> Each *generating unit* must be fitted with a governor and a *voltage* regulator so that, following the occurrence of any *credible contingency event* and *changed power system* conditions after *disconnection* of the faulted element, the *generating unit* must be capable of delivering to the *transmission* or *distribution system active power* and *reactive power* sufficient to ensure that the *connection point voltage* is within the range for continuous uninterrupted operation for that *generating unit*.

Compliance assurance

Compliance assurance and ongoing verification of adherence to the Technical Rules follow the same procedures as those for conventional generators.

A.7 New Zealand

The proposed FRT requirements currently under consultation apply to all generators, regardless of technology. However, Transpower has considered the performance of wind generators in relation to the proposed fault ride through requirements and summarises the capabilities as follows;

- Typical double fed induction generators (DFIG) can ride through three phase faults down to 5% retained voltage for a period of 0.2s but will not meet the zero voltage requirement without the adoption of advanced control systems. An advanced control system such as the Advanced Grid Options (AGO) offered by Vestas on its DFIG generators is likely to meet the FRT requirements.
- A full scale frequency converter (FSFC) connected wind turbine is capable of riding through three phase faults resulting in a voltage collapse to zero for a period of 0.85s and is likely to be compliant with the FRT requirement.

In 2005 the Electricity Commission of new Zealand instigated a wind generation investigation project (WGIP)[48] to assess the likely impact of wind generation development over the next 5 to 10 years. The study identified wider power system and electricity market implications of additional wind generation and provided recommendations on how to best resolve issues identified to enable the development of wind generation on a “level playing field” with other generation sources.

One of the main recommendations of the WGIP report published in June 2007 is the need for wind generators to have fault ride through capability.

At present there are no formal compliance requirements or processes written into the EGRs but a guidance document for the routine testing of assets has been produced. It should be noted that with the Transpower proposal to introduce FRT requirements to the Electricity Governance Rules currently under consultation with the EC and the WGIP recommendation that fault ride through requirements should be established for wind generators, it is likely that such requirements will be reflected in future versions of the Explanatory Guide for asset testing.

[48] http://www.electricitycommission.govt.nz/pdfs/opdev/comqual/windgen/implications/Summary-Report-July07.pdf

APPENDIX B - FRT REQUIREMENTS QUESTIONNAIRE

INTRODUCTION	Fault Ride Through Requirements: an International Review

One of the key connection requirements for new generators relates to their capability to ride through transmission network faults. This requirement is critical to network stability and rapid recovery of active power following restoration of the transmission voltage.

KEMA has been commissioned by Eigrid, the Irish System Operator, to perform an international review of the requirements stated in Grid Codes (or other pertinent document) of the Fault Ride Through requirements for generators, both conventional and renewable.

This Questionnaire is developed to answer, per country, the following issues (summarised):

• *Understand the power system metrics and how they compare to Ireland*
• *Obtain an understanding of the requirements of the Grid Code regarding fault ride through*
• *How the minimum standard was established i.e. what are the operating characteristics of the particular transmission network that led to the particular definition of FRT; has the value been changed and if so why;*
• *How other Grid Codes propose to deal with a high penetration of asynchronous generation expected through the proliferation of wind turbine generating systems;*
• *How other countries assess FRT compliance for connection offers, at commissioning and for the lifetime of the Generation Unit;*

Any queries you may have about the questionnaire should be addressed to:

Iain Wallace +44 1355 813 267 iain.wallace@kema.com

Dragana Popovic + 44 20 731708165 dragana.popovic@kema.com

TSO - Country	Fault Ride Through Requirements: an International Review
ID	Topic
000	Index
100	Transmission system metrics
200	Current FRT requirements
300	History and rationale
400	Compliance process & assurance

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TSO - Country	Fault Ride Through Requirements: an International Review		
ID	Query	Answer	Comment
100	**Transmission system metrics**		
101	**Total Energy Demand (TWh)**		
102	**Peak Demand (GW)**		
103	**Connected Gen Capacity (GW)**		
	Types of generation		
104	*coal*		
105	*gas*		
106	*hydro*		
107	*renewable - wind*		
108	*renewable - solar*		
109	*other*		
110	**Total length of overhead lines, by voltage level (kms)**		
111	**Total length of cables, by voltage level (kms)**		
112	**Inter-connection capacity (MW)**		

TSO - Country	Fault Ride Through Requirements: an International Review		
ID	**Query**	**Answer**	**Comment**
200	**Current FRT requirements**		
201	What are the FRT requirements for conventional generators connected to the transmission system? Please provide the exact wording as stated in the relevant document(s).		
202	Do FRT requirements vary by generator size or network conditions at point of connection?		
203	Have separate criteria been developed for renewable generators connected to the transmission system? Do FRT requirements for onshore and offshore wind generators differ?		
204	In which documents are the requirements specified?		
205	Please provide relevant Codes or documents that specify FRT requirements where available and clearly indicate the relevant section/close.		

TSO - Country	Fault Ride Through Requirements: an International Review		
ID	**Query**	**Answer**	**Comment**
300	**History and rationale**		
301	When was the requirement for generator FRT capability first documented as a formal requirement?		
302	What is the primary reason for current FRT requirements (eg were FRT requirements established to meet system stability, protection operation or other requirements)?		
303	What underlying studies were conducted in order to arrive at the current FRT requirements? Please describe in brief the nature of the studies and main assumptions (eg power factor, stability requirements under consideration, reactive power considerations etc)		
304	Is there a minimum fault level considered at the point of connection for compliance assessmet?		
305	Please outline development of FRT requirement and description from inception to current version; provide date and reason for change.		

TSO - Country	Fault Ride Through Requirements: an International Review		
ID	**Query**	**Answer**	**Comment**
400	**Compliance process & assurance**		
401	**Connection application phase:** Please describe briefly the connection application process in relation to generator and TO responsibilities and requirements wrt information provision.		
402	Connection application phase: What data or study results is generator expected to provide?		
403	Connection application phase: Does TO perform own system study?		
404	Connection application phase: What is course of action in event of non-compliance being identified at this stage?		
405	**Commissioning phase:** Please describe briefly the commissioning process in terms of generator and TO obligations and responsibilities.		
406	Commissioning phase: What information and data is generator expected to provide?		
407	Commissioning phase: How does TO validate own or generator modelling results?		
408	Commissioning phase: What test results does TO wish to witness / receive?		
409	Commissioning phase: What is course of action in event of non-compliance?		
410	Commissioning phase: What is course of action in event of non-compliance? In cases where a non-compliant generator is allowed to connect on an interim basis, please outline the associated implications and requirements for achieving full operational right. In cases where a derogation is to be sought, please outline the derogation process.		

411	**Ongoing operation:** Describe briefly the responsibilities and obligations of generators and TO in relation to ongoing compliance.		
412	Ongoing operation: What situations may trigger a re-evaluation of generator FRT?		
413	Ongoing operation: Is generator FRT compliance routinely / periodically appraised? ?		
414	Ongoing operation: What information has to be provided to TO should a non-compliance arise?		
415	Ongoing operation: What is course of action in event generator becomes non-compliant?		
416	Please provide relevant documents, where available, that describe compliance process for conventional and renewable generators.		