# Fault Ride Through Principles

# and

# Grid Code Proposed Changes

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## Contents

## 1 Background

The electrical power system worldwide has been at the core of economic growth and development since the late 1890's. In particular following the World Exhibition in Buffalo in 1896 the Nikola Tesla designed three phase synchronised power system has become the standard worldwide. During the early twentieth century, electricity systems grew in size and their importance to the economic development became inextricably linked. This placed increased strategic importance on the resilience of the power system to withstand a wide range of probable and less probable events and disturbances without resulting in the loss of a significant part of the power system.

During the 1930's the issue of resilience of power systems to a wide range of dynamic stability issues became more prevalent. This led to significant analysis on the causes and nature of the stability of power systems over the following three decades. By the 1970's a fundamental understanding of power system stability had been developed and mechanisms for managing stability implemented and tested. By the 1990's, with the deregulation of the electricity industry allowing third-party access and competition, standards were developed that detailed the minimum functional capabilities for all generators connecting to the system. These have been encapsulated in Grid Codes worldwide. However, by design the Grid Codes have specified rules without reference to the fundamental issues underlying the cause of instability in the first place. In addition, different systems have developed different rule sets which are no longer directly related to the fundamentals of the stability issue. Others have clauses which are ambiguous in how they are to be interpreted and enforced.

To this end, this paper proposes setting out the core fundamentals of the stability for power systems, the key factors which should be considered in setting requirements from generators, and a proposed text for the Grid Code to address these concerns for the power system of Ireland. The text will cover principles and structure but will not propose values as these will be for full consideration of the FRT Working Group to present to the full Grid Code Review Panel, and for ultimate approval by the CER.

## 2 Foundations of Stability

Three phase alternating current power systems have an intrinsic strength as each unit is "*locked*" into operation with other units at the same frequency, phase and voltage magnitude (allowing for transformation). This operation, as one collective, arises due to the coherency of the three phase generation output and is a direct result of the electro-magnetic interaction at the heart of synchronous systems.

During voltage disturbances, individual units are subjected to stresses which can result in one or more units losing synchronism with the remaining collective. Should this happen, the generators that lose synchronism will suffer severe mechanical stresses, and damage to the plant is probable. This is why individual units have internal protection to try to disconnect their unit from the system before this happens and avoid the stresses if possible.

From a system perspective, a unit losing synchronism has the potential to pull other units out of synchronism with it. This loss of synchronism will not only result in the loss of the generator(s) power output, with resulting impacts on frequency, but will also significantly impact on rotor and load angles on the remaining synchronised units. To this end, loss of synchronism is a more severe impact to the system than just the tripping of a unit. When the rotor angle between units changes by more than 180 degrees loss of synchronism will ensue. In practice, it will happen well before this point. This loss of synchronism has associated impacts on both frequency and remaining rotor and load angles on generators, potentially leading to partial or total blackout of the system.

Because of this severe impact, prudent system operation dictates that no probable contingency should ever lead to the situation where loss of synchronism could occur. In addition, it is prudent to ensure that a range of less probable events do not cause loss of synchronism. However, this would also need to balance system security and overall cost to the system. In principle, this consideration needs to factor in the capital costs of remedying the issue on the unit with the ongoing operational costs to the consumer and increased complexity to the operator. This is difficult to estimate.

To prevent operating a power system where loss of synchronism was a possibility a detailed understanding of the causes of the phenomena was required. The theory surrounding these issues was developed in the 1930's-1950's and has been thoroughly tested through operation of power systems globally ever since. The key factors summarised in the recent textbooks and articles are as follows.

In its simplest form, a synchronous generator can be seen as an internal electromagnetic force (EMF) behind a reactance (Figure 1). The reactance predominately arises from the windings of the stator (alternator). The greater the number of windings and the longer winding lengths will increase the magnetic flux linkage between rotor and stator which will increase the terminal voltage and reduce the current ceteris paribus. The internal EMF is directly related to the size of the rotor circuit energising DC source, the speed of rotation of the rotor with respect to the stator and the number of windings on the rotor. The speed of rotation of the rotor is linked directly to the prime mover and associated turbine governor controls and inertia. During disturbances the dominant factor in the change of rotation speed is the inertia of the plant.

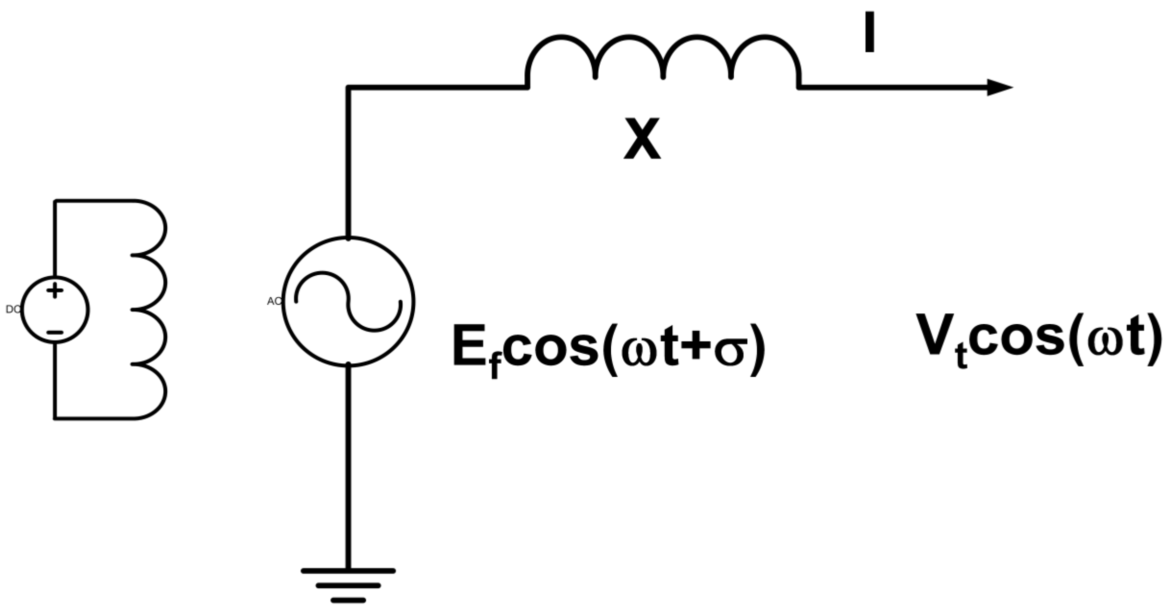


**Figure 1 Classical Lossless Steady State Single Phase Synchronous Generator Model**

From an electrical perspective, employing steady state assumptions, the internal EMF (E) is related to the current (I) and the terminal voltage of the generator (V) by the following vector diagrams. The load angle (δ) between the internal EMF and the terminal voltage is directly related to the synchronism of the generator. Should this angle on any specific unit exceed 90 degrees the unit will lose synchronism. Fault Ride Through standards are in essence trying to ensure through a range of disturbances that this internal load angle on any given unit does not exceed 90 degrees. The load angle is directly related to the reactance of the generator and the magnitude of the excitation (Figure 2).

Under steady-state conditions, there is equilibrium between the mechanical power input into the turbine and the electrical power output from each machine, resulting in a constant rotating speed. If the system is disturbed this equilibrium is upset, resulting in an acceleration or deceleration of the rotors and variations on their relative angular position. The power-angle relationship is non-linear. Beyond a certain limit, an increase in angular separation between rotors is accompanied by a decrease in power transfer, which increases the angular separation further and leads to instability.

This leads to fluctuations in the machine power output, current and voltage. Typically, generator protection is installed to disconnect the machine as the rotor angle approaches 180°.

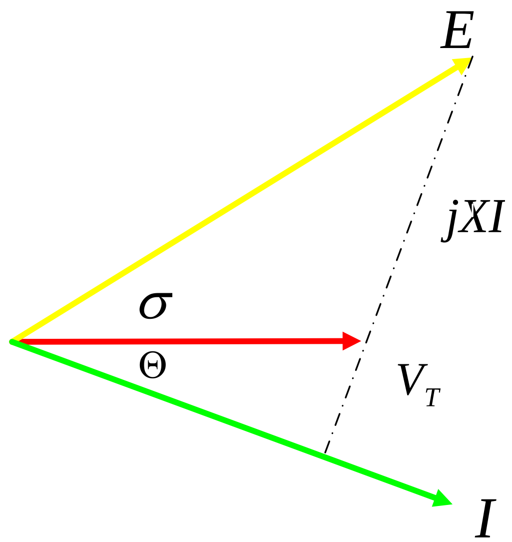


Figure 2 Classic Vector Diagram

Where the unit is producing leading MVAr at constant power output (**Error! Reference source not ound.**) it can be seen that the load angle increases. This has consequences for stability of generators in producing leading MVArs.

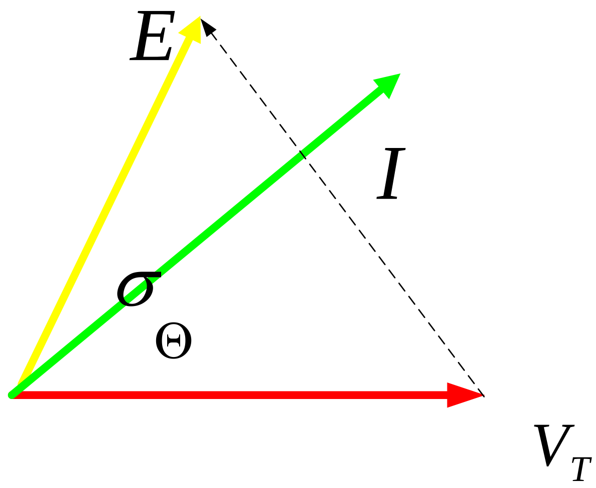


Figure 3 Classic Vector Diagram of a unit in leading reactive power

## 2.1 Equal Area Criterion

Another way to look at Fault Ride Through is to use the Equal Area Criterion, which is a graphical method used to explain and evaluate the stability of a power system following a disturbance. In the most simple case, it describes the stability of a single machine connected to an infinite busbar, but it can be extended to multi-machine cases. The electrical power output produced by a generator can be written as:

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Here, $P_{max}$ is the maximum power output of the machine, E and V are the voltages at the sending and receiving end of source reactance $X_s$, and the load angle is given by $\delta$. The power-angle curve thus has a sinusoidal shape, as shown in Figure 4.

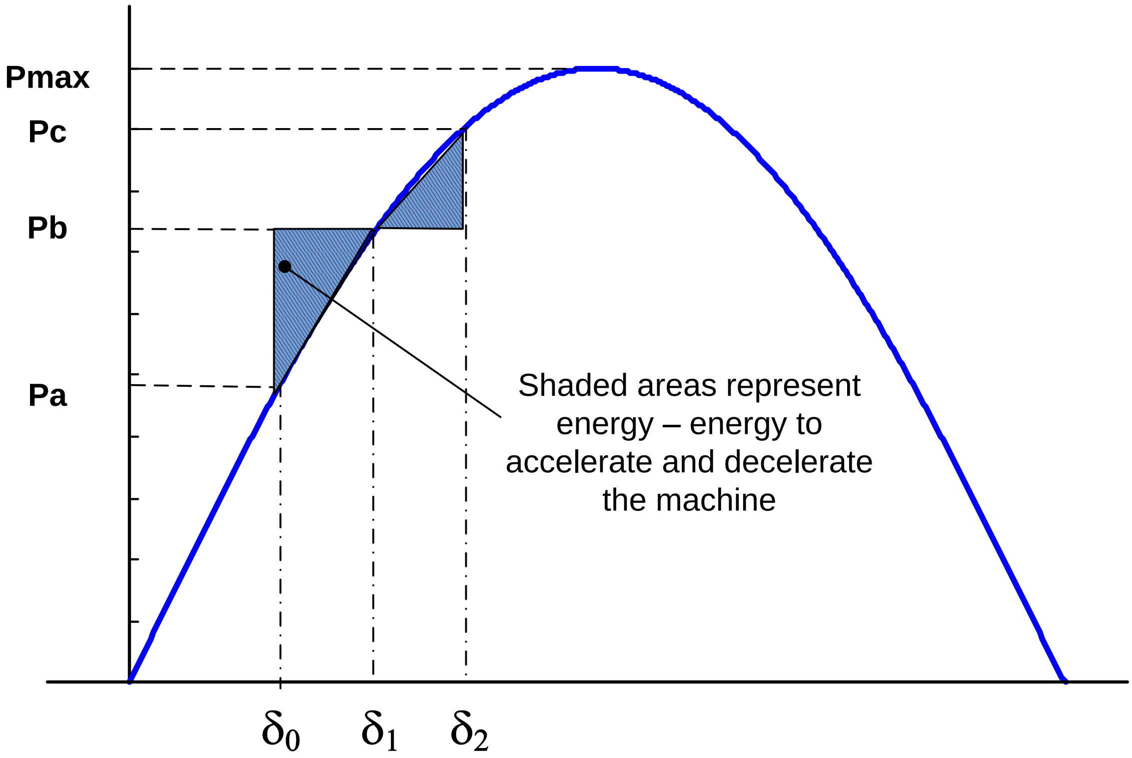



**Figure 4 Machine Power-Angle relationship, and Equal Area Criterion – stable case**

Referring to Figure 4, and ignoring any losses, if the machine is initially operating in equilibrium at Pa and angle $\delta_0$, and the mechanical power is increased to Pb, then the machine will accelerate. This is because the mechanical power in is greater than the electrical power out. The load angle will increase to $\delta_1$, where the mechanical and electrical powers are equal. However, the inertia of the machine means that the load angle will keep increasing up to angle $\delta_2$. At this stage, the electrical power out is greater than the mechanical power in, and the machine decelerates. In this way, a new equilibrium will be reached eventually at load angle $\delta_1$. For stability, the two areas in Figure 4, representing accelerating and decelerating energy should be equal.

When a fault occurs, the power-angle curve changes because the machine may no longer be able to export all of its power. For a very severe, bolted three-phase fault, no electrical power can be exported from the machine, whereas for a minor voltage dip, the power export may only decrease slightly. Referring to Figure 5, Pa represents the initial power output, and mechanical power input to the machine, operating at load angle $\delta_0$. A severe three-phase fault occurs, and the power-angle curve changes to the red line. The machine can now only export electrical power Pf, while the mechanical power into the machine is Pa. The machine experiences huge acceleration because of the excess mechanical input power. At some point, the fault will be cleared by protection equipment, by which time, the load angle has increased to $\delta_1$. The machine decelerates at this point, but if the load angle goes beyond $\delta_2$ because of machine inertia, the mechanical power input will be greater than the electrical power output, and the machine becomes unstable, and will trip off the system.

The fault 'duration' – the length of time it takes for the angle to increase from $\delta_0$ to $\delta_1$ is dependent on the protection installed. The accelerating energy is dependent upon the machine parameters, especially the machine inertia, and the operating point of the machine, as well as the severity of the fault. Fault Ride Through is enhanced by ensuring that the accelerating energy is minimized, so that the machine angle does not increase beyond a point of no return. Machines with relatively lower inertia will experience larger angular acceleration. On some machines, braking resistors are installed which serve to divert the mechanical input power to the machine when a fault occurs, lessening the angular acceleration.

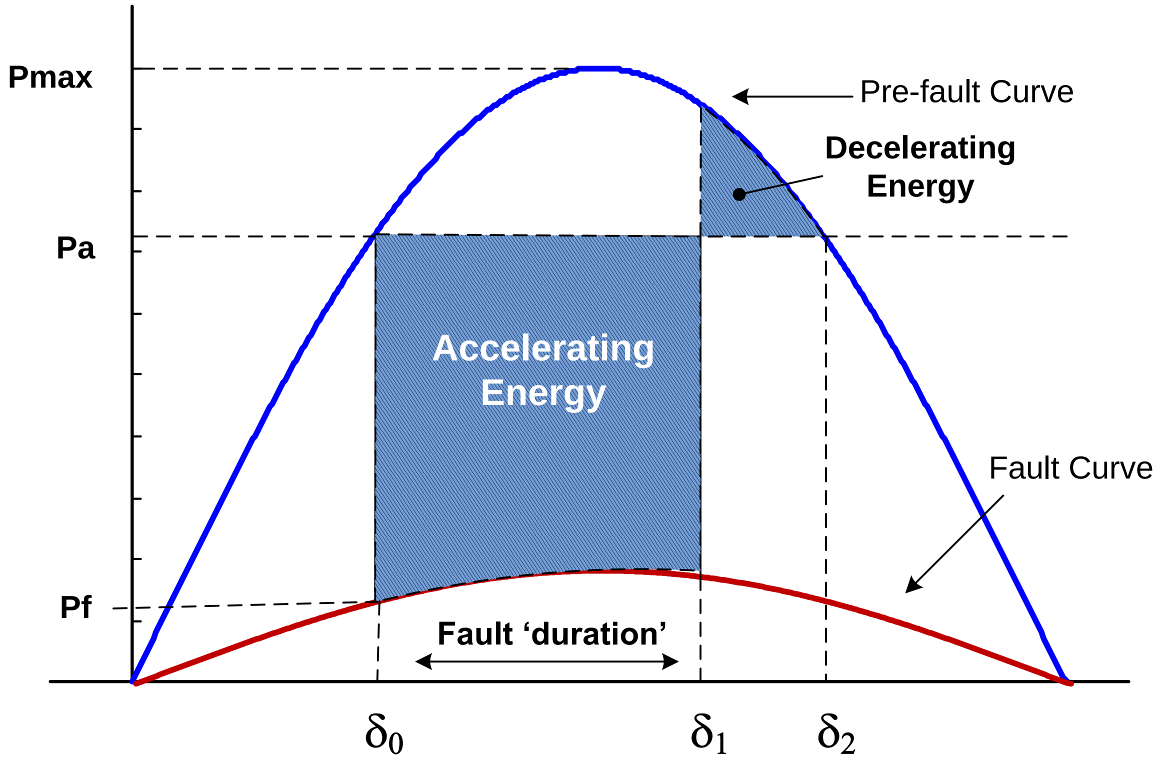



**Figure 5 Application of Equal Area Criterion for a severe fault**

Another point to note is the possible change in reactance between a machine and the rest of the power system after a fault has occurred. Figure 6 shows a simple equivalent circuit for when a machine is connected to the system. The overall impedance $X_s$ can be calculated and this determines the pre-fault power-angle curve. If a fault occurs on a transmission line, and this line is disconnected following the fault, the overall impedance will change (to a higher value). It is clear from the power-angle equation that higher value of $X_s$ will lead to a flatter curve (as shown in Figure 7). The new post-fault curve has a lower maximum – less power can now be exported through the transmission system. The machine may still be able to produce its maximum power, but it will be closer to instability than had the pre-fault curve still applied. In applying the equal area criterion to this situation, the decelerating energy would be lower, and so the critical clearance time would also be reduced, making fault ride-through more challenging. Fault Ride Through enhancement is discussed in more detail in the next section.

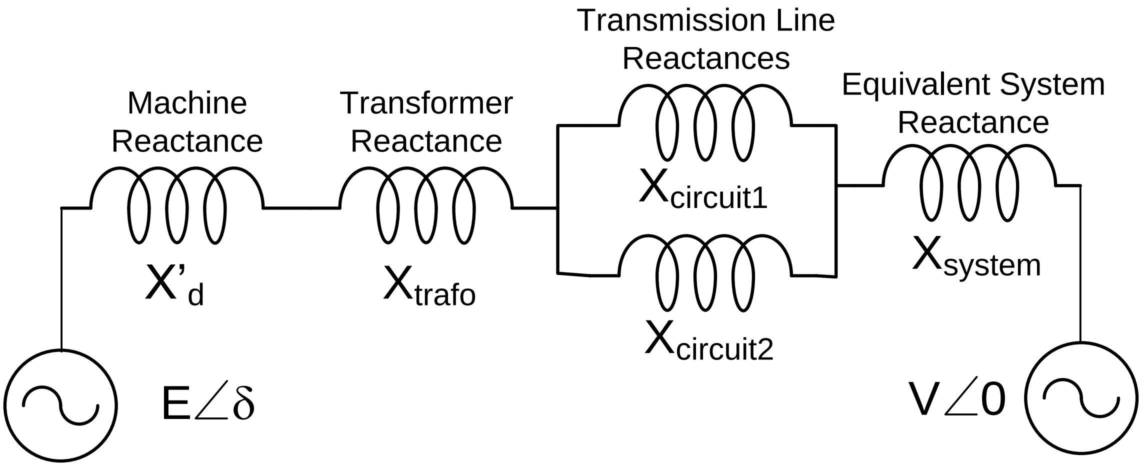



**Figure 6 Equivalent circuit of a machine connected through a transformer and two transmission lines to the rest of the power system**

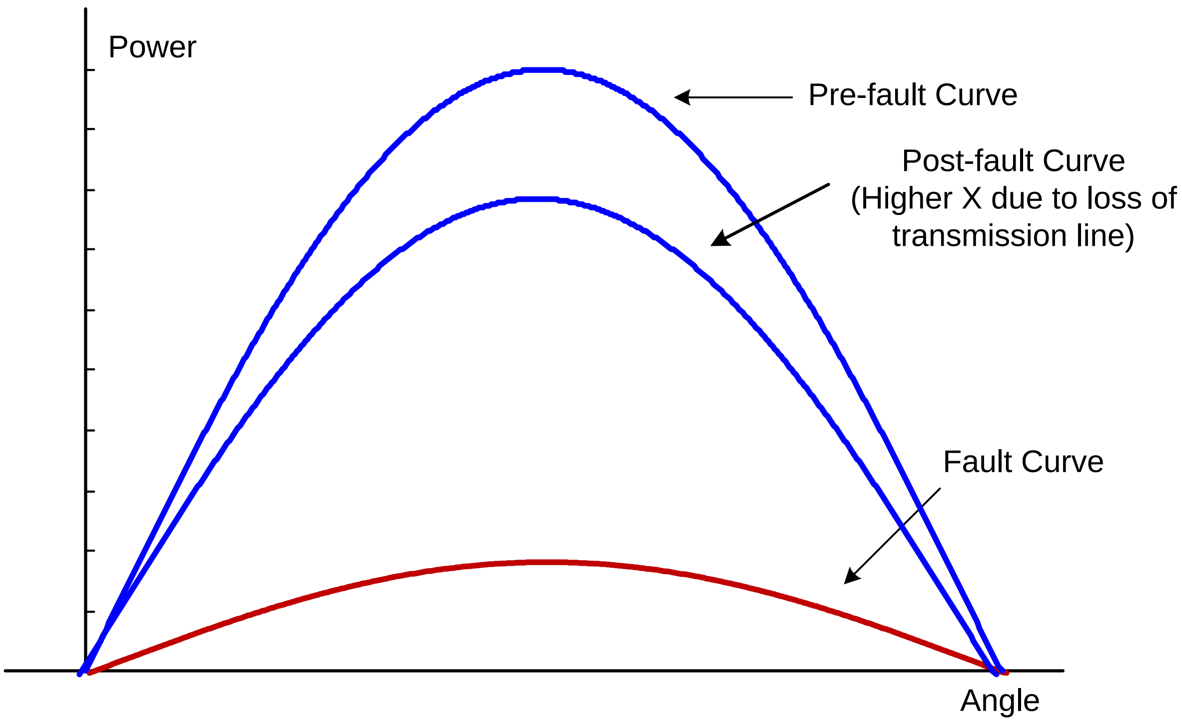



**Figure 7 Different power-angle curves: The fault curve is low due to the reduced voltage during the fault, and the post-fault curve is lower than pre-fault because of the higher $X_s$ value caused by the loss of a circuit**

## 3 Key Factors Surrounding FRT

There are two key factors in managing the load angle increase of a generator during and following a voltage disturbance - those directly related to the design of the generator and those related to the network.

### 3.1 Generator Design

**CONTROLLING MECHANICAL ACCELERATIONS**

During a voltage disturbance near a generator the electrical power sent out from the unit decreases as the voltage is close or near to zero. This results, while the voltage remains low, in a net power increases into the rotational mass of the turbine and alternator which causes the generator to physically speed up. This acceleration impacts on the magnetic flux linkage in the air gap between rotor and stator which will lead to changes to the load angle. The greater this acceleration the greater the probability of loss of synchronism, ceteris paribus.

There are three main mechanisms which can limit the acceleration of the generator in these circumstances;

- the rotational inertia of the turbine and alternator;
- the governor controls to the turbine; and
- pre contingency MW output

With increased inertia the generator will naturally accelerate slower than a lighter inertia machine as more energy is required to physically speed up the machine. This inertia arises directly from the design of the generator and will always operate in times of a power imbalance between electrical output and mechanical input however it is caused – it is a passive control. However the trend in the build of generators over the last 3 decades has been for smaller inertias for similar electrical sized machines.

The use of governor controls to limit the power input during these power imbalances also assists. In this case on the detection of the speed of the generator increasing the governor can dip closing off steam flow to the turbine and reducing the net power input into the rotational energy of the machine. However it is noted that this control, while implemented on large interconnected systems, does not operate as quickly as inertia and may have consequences for the spinning reserve provision of the unit during and immediately following the disturbance. In addition the use of fast valving is performance of the governor that is currently not specified by the Grid Code V3.4.

Finally the pre contingency power output of the generator has a direct impact on the potential power imbalance on the unit. A possible mitigation strategy is to limit the power output of the unit at times.

**INCREASING THE ELECTRO MAGNETIC COUPLING BETWEEN GENERATOR AND SYSTEM**

During a disturbance the impedance that the generator presents to the system directly impacts on the load angle. If this impedance can be reduced (or the reactance increased) the load angle for a given power output level can be reduced. This impedance is related to the level and number of windings in the stator and the electro magnetic coupling between rotor and stator. A good indicator of this impedance is the MVA rating of the alternator. In recent years there has been a trend to design generators with MVA closer to the registered rated output of the generator, in effect with a higher impedance to the system. The number, size and shape of the stator windings are a design feature of the generator and once built will always act as designed – it is a passive control.

In addition during a disturbance the internal EMF can be increased in a short period of time to reduce the load angle between EMF and terminal voltage. The development of excitation systems over the years has focused on these issues. In particular the gain of the control system on the excitation and its speed of reaction have a noted impact. However these gain settings have implications for voltage oscillations and inter area modes which need to be tuned carefully. This type of control is active.

Finally it is noted that increasing MW setpoint of a unit, ceteris paribus, increases the load angle.

## 3.2 Network Design

### PROTECTION PHILOSOPHY INCLUDING CLEARING TIMES

The network protection that clears faults will have a direct bearing on the length of time a voltage dip can remain on the system and hence the opportunity for the generator to accelerate and pull out of synchronism. It is clear that this protection if it operates quickly enough can significantly reduce the possibility of a loss of synchronism and is a key component in a system FRT strategy.

Modern day protection relays have the operational capability of detecting a fault and operating a circuit breaker of between 80 and 120 ms and is unlikely, in the next decade, to materially improve. In the event that a relay detects a fault but fails to open the circuit breaker, circuit breaker fail (CBF) protection can then operate to make a second attempt to clear the fault or failing that to strip the busbar section where the plant feeds into. This operation can take approximately 200 ms. CBF fail protection is now a standard on all new 110 kV, 220 kV and 400 kV stations.

It is noted that some older relays and circuit breakers still exist on the power system today. In a review of the operation of protection to date it is also noted that approximately 1 event in 50 protection fails to operate as expected.

### NETWORK STRENGTH AT POINT OF CONNECTION INCLUDING TOPOLOGY AND PLANT SET POINTS

The electrical strength of the location at the connection point directly impacts on a units FRT capability. In this regard generators that are electrically closer to other synchronous generators will have increased synchronising torques (the forces that keep a generator in synchronism) and will remain synchronised for a wider range of disturbances. A generator is electrically closer to another unit when the impedance between them is reduced. This is generally achieved by the addition of some form of parallel paths and requires the construction of transmission infrastructure including overhead lines and cables. In large systems the application of series capacitors is also used.

It is acknowledged that the operation of the power system can significantly effect the topology of the network and the dispatch and scheduling of plant. These issues are outside the control of an individual generator.

## 4 Proposed Grid Code Text

### REASONING FOR TEXT CHANGE

The following text is proposed to address any ambiguities in the original Grid Code with respect to FRT. The reasons for the changes are noted and where appropriate linked to the principles as discussed.

1. *Unless explicitly stated all conditions specified apply over the full operating capabilities of the **Generation Unit** at the **Connection Point**.*
   This text is added to remove any ambiguity that a unit has to have an FRT capability at the point of connection and not at some other part of the network or indeed at an infinite bus.

2. (h) *remain synchronised during and following any **Fault Disturbance** anywhere on the power system which could result in **Voltage** dips at the **HV** terminals of the **Generator Transformer** of no greater than 95% of nominal **Voltage** (5% retained) for duration Y1 seconds and **Voltage** dips of no greater than 50% of nominal **Voltage** (i.e. 50% retained) for duration of Z1 seconds*
   The concept of a **Fault Disturbance** is clarifying that the Grid Code is only requesting generators to have this capability for possible and probable disturbances that would require a unit to stay on the system. In addition it clarifies to a degree what is deemed as a reasonable set of issues that can cause the voltage dip. Finally this clarification is bounded still to no

greater than 0.95 dip – it does not increase the standard required.

3. *Following the fault clearance the **Generation Unit** should return to prefault conditions subject to its normal **Governor Control System** and **Automatic Voltage Regulator** response. The use of **Extraordinary Governor and AVR** response to remain synchronised during and following a fault is prohibited;*
The introduction of a new term **Extraordinary Governor and AVR** response is to clarify that actions such as fast valving and breaking resistors are non standard and can not be used for the purposes of meeting the Grid Code standard on FRT.

**FULL TEXT CHANGE**

### 4.1.1 CC.7.3 Generators

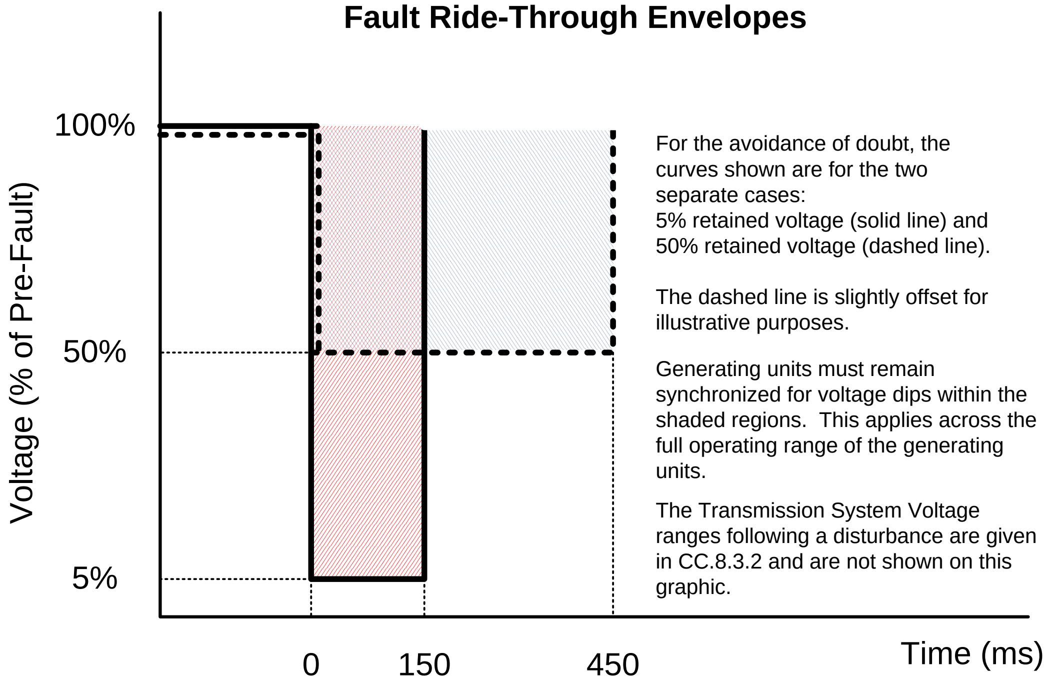
CC.7.3.1 The conditions specified in this section of the code apply to all **Generation Units** connected to or connecting to the **Transmission System**. Unless explicitly stated all conditions specified apply over the full operating capabilities of the **Generation Unit** at the **Connection Point**.

For all **Generation Units** where **Secondary Fuel Registered Capacity** is different than **Primary Fuel Registered Capacity** all appropriate **Connection Conditions** must be met or agreed with the **TSO**.

CC.7.3.1.1 Each **Generation Unit,** shall, as a minimum, have the following capabilities:

(a) operate continuously at normal rated output at **Transmission System Frequencies** in the range 49.5Hz to 50.5Hz;
(b) remain synchronised to the **Transmission System** at **Transmission System Frequencies** within the range 47.5Hz to 52.0Hz for a duration of 60 minutes;
(c) remain synchronised to the **Transmission System** at **Transmission System Frequencies** within the range 47.0Hz to 47.5Hz for a duration of 20 seconds required each time the **Frequency** is below 47.5Hz;
(d) remain synchronised to the **Transmission System** during rate of change of **Transmission System Frequency** of values up to and including 0.5 Hz per second;
(e) sustained operation at the specified **Minimum Generation** within the range 49.8 to 51.0 Hz;
(f) remain synchronised to the **Transmission System** at normal rated output at **Transmission System Voltages** within the ranges specified in CC.8.3.2 for step changes in **Transmission System Voltage** of up to 10%.
(g) sustained operation in accordance with the **Reactive Power** capability as required by CC.7.3.6 at **Transmission System Voltages** within the ranges specified in CC.8.3.2, unless otherwise specified;
(h) remain synchronised during and following any **Fault Disturbance** anywhere on the **Power System** which could result in **Voltage** dips at the **HV** terminals of the **Generator Transformer** of no greater than 95% of nominal **Voltage** (5% retained) for ~~duration 0.2 seconds~~ fault durations up to and including the **Fault Ride-Through Times** as defined in the table below and **Voltage** dips of no

greater than 50% of nominal **Voltage** (i.e. 50% retained) for ~~duration of 0.6 seconds~~ fault durations up to and including the **Fault Ride-Through Times** as defined in the table below (see also **Fault Ride-Through** Envelopes below). Following the fault clearance the **Generation Unit** should return to prefault conditions subject to its normal **Governor Control System** and **Automatic Voltage Regulator** response~~;~~. The use of **Extraordinary Governor Response** and/or **Extraordinary AVR Response** to remain synchronised during and following a fault is prohibited unless specifically agreed with the **TSO**, such agreement not be unreasonably withheld.




| VOLTAGE DIP MAGNITUDE | **Fault Ride-Through Times** | | |
|---|---|---|---|
| | 400 kV System | 220 kV System | 110 kV System |
| 95% (5% retained) | 150 ms | 150 ms | 150 ms |
| 50% (50% retained) | 450 ms | 450 ms | 450 ms |

***Glossary Definitions:***

**Fault Disturbance**

Any type of fault including, but not limited to, single line to ground, line to line and three-phase short-circuits, in any single item of **Plant** anywhere in the **Transmission System** where the operation of the **TSO** protection will not disconnect the **Generator Plant** from the existing or planned **Transmission System** under normal or **Scheduled Outages** conditions. For the avoidance of doubt this **Fault Disturbance** can include bus zone protection.

**Extraordinary Governor Response**

Any response to a **Voltage Dip** that requires an extraordinary response from normal behaviour of the **Governor Control System** of a **Generation Unit.** For the avoidance of doubt any action other than **Governor Control System** with respect to **Frequency** dips is deemed to be an **Extraordinary Governor Response**. Where such schemes, including fast valving, are being considered by a **Generator** they need to be formally agreed with the **TSO** before implementation, such agreement not to be unreasonably withheld.

**Extraordinary AVR Response**

Any response to a **Voltage Dip** that requires an extraordinary response from normal behaviour of the **Automatic Voltage Regulator** of a **Generation Unit.** For the avoidance of doubt any action of an **Automatic Voltage Regulator,** which results in anything other than an adjustment of the excitation field current is deemed to be an **Extraordinary AVR Response**. Where such schemes, including fast valving, are being considered by a **Generator** they need to be formally agreed with the **TSO** before implementation, such agreement not to be unreasonably withheld.

**Critical Fault Clearance Time**

The longest fault duration not leading to out-of-step conditions such as pole-slipping in a **Generating Unit** following a **Fault Disturbance**. **Critical Fault Clearance Time** will vary according to the active and reactive power output of the **Generating Unit**. The minimum **Critical Fault Clearance Time** for a particular **Fault Disturbance** is likely to occur when the **Generating Unit** is at maximum **Active Power** output and maximum leading **Reactive Power** output.

**Fault Ride-Through**

The ability of a **Generating Unit** to stay **Synchronised** to the **Transmission System** during and following a **Fault Disturbance**.

**Fault Ride-Through Time**

The required fault duration that a **Generating Unit** shall ride through for a particular **Fault Disturbance**, and is equivalent to the **Critical Fault Clearance Time.**

## 5 Conclusions

A discussion of the factors impacting FRT has been presented and a set of textual changes to calrify and remove ambiguity on the requirements for a generator in the Grid Code proposed. Specifically a generator is to design their unit with sufficient inertia and reactance at the connection point to maintain synchronism for a range of fault disturbances anywhere on the power system which will produce up to a 0.95 voltage dip at the HV bushings of the generator transformer. A generator can get estimates of the likely network configuration from the system operator and does not have to concern themselves with inter area modes. Finally the use of devices such as fast valving is prohibited.

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