Connection Study Requirements

GL-EA-0953

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Version	Date	Change
1.0	28 June 2021	Initial Issue
2.0	17 March 2022	Minor update to incorporate comments from users
3.0	4 October 2022	Change in assessment of where a Point of Connection to the Grid exists
4.0	17 May 2023	Minor changes including document name change and links updated.
5.0	30 January 2025	Harmonics distortion study specifics removed (now part of Grid Owner processes) and minor changes to align with new GL-EA-404.
6.0	7 July 2025	General writing overhaul to improve clarity; some technical updates to studies e.g. FRT
7.0	21 October 2025	Minor update to clarify the fault ride through section.
8.0	1 July 2026	Guidance aligned with CACTIS requirements; 10-30 MW FRT study section added in appendix B.

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Table of Contents

Introduction

This document assists you, the asset owner, to understand the requirements for completing connection studies when connecting a generation asset to the New Zealand power system. Such connections change the operational environment and therefore require assessment to anticipate any challenges that may be introduced.

The System Operator provides this guideline to support you in the process of commissioning generation. Refer to the document suite on the next page for hyperlinks to the other helpful documents and for an idea of when you should consult them. In particular, we expect you to read this document alongside the following:

- the *Electricity Industry Participation Code 2010* (the Code), especially Part 8, which includes the most up-to-date performance requirements;
- the *Connected Asset Commissioning, Testing, and Information Standard* (CACTIS), especially Chapter 5;
- the most up-to-date *Certified Policy Statement*;
- *GL-EA-010* Generator Testing Requirements; and
- *GL-EA-716* Modelling Requirements for Synchronous Assets and *GL-EA-1311* Modelling Requirements for Inverter-based Resources.

Note: You are responsible for reading, understanding, and complying with all your asset owner obligations as stipulated in the Code (and any incorporated documents, such as the CACTIS). If you engage a consultant for the purpose of conducting your connection studies, you should share all relevant documentation with them so they are aware of our requirements.

Our Expectations

Early submission of the connection studies and the connection studies report is key to ensuring the commissioning timeline can proceed without delay.

The timelines set out in CACTIS represent the deadlines by which the **final version** of the connection studies report, and the associated models must be submitted to the System Operator. Failure to meet these timelines may have direct impacts on the project's **commissioning schedule**.

Accordingly, asset owners are strongly encouraged to commence connection studies early stage of project, particularly when the key parameters of your asset are finalised and can permit accurate assessment.

If you make any changes to key parameters that could affect the results of your connection studies, discuss these with us as early as possible as some or all studies may have to be repeated with new parameter values. Similarly, if any non-compliances or technical requirement violations occur during your connection studies, you must discuss and seek resolution with us as early as possible.

Intended Use of the Connection Studies

The connection studies outlined in this document are used by the System Operator to:

- assess whether the generating asset meets the applicable requirements set out in the Code;
- assess the generating asset's ability to help the System Operator plan and meet the principal performance obligations (PPOs);
- anticipate any potential operational issues that can constrain the operation of the new generating unit;
- assess the impact of the new generation connection on power system stability and supply security;
- assess measures for technical requirements that are not fulfilled by the generating station;
- minimise risk during commissioning and testing; and
- ensure power system operation and other grid connection parties are not affected by the generation asset.

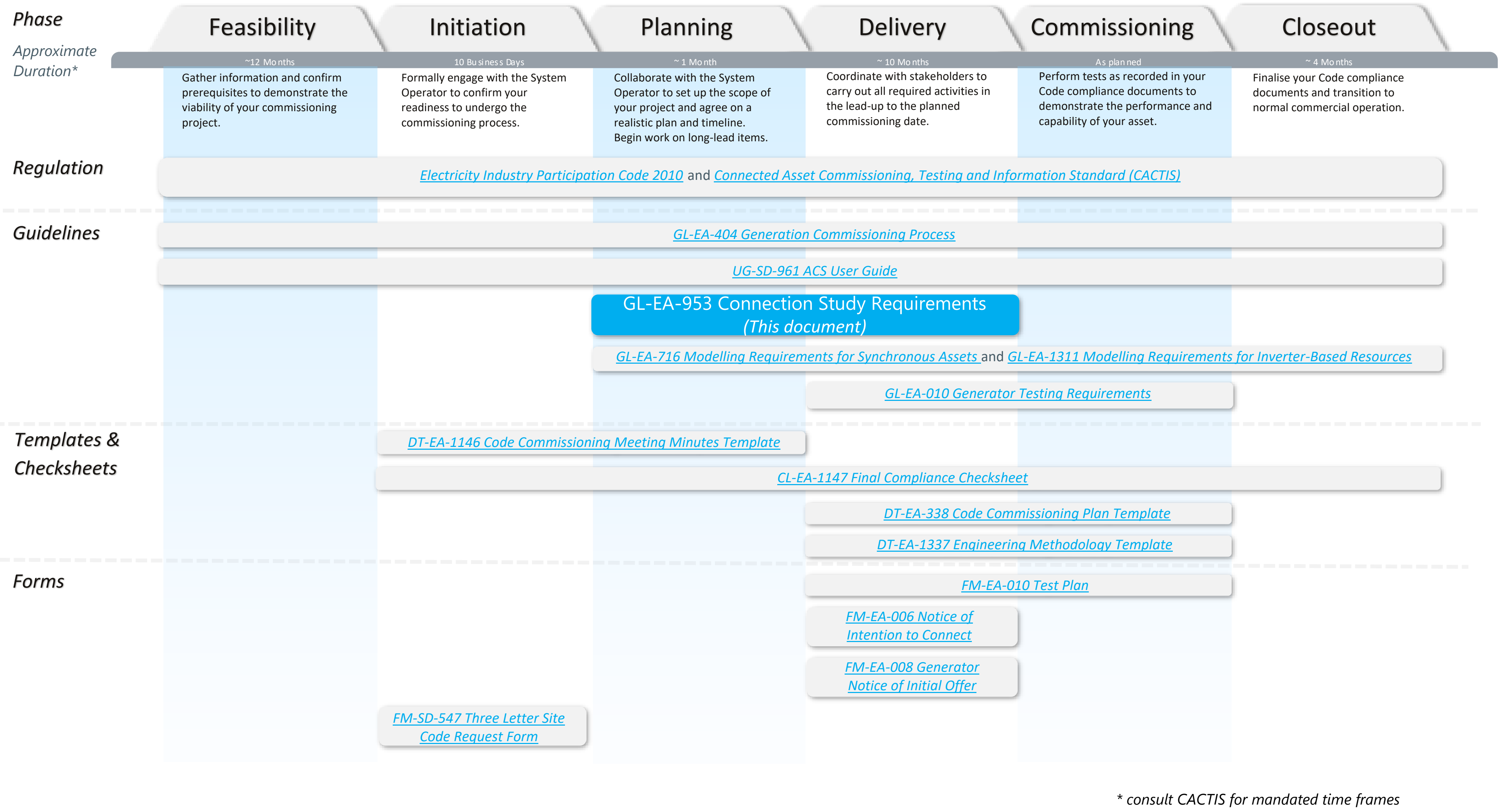


Figure 1 - Supporting Documentation Suite

1 Abbreviations

Abbreviation	Full Form/Explanation
ACS	Asset Capability Statement
AO	Asset Owner
AOPO	Asset Owner Performance Obligations
AVR	Automatic Voltage Regulator
CACTIS	Connected Asset Commissioning, Testing and Information Standard
CFCT	Critical Fault Clearing Time
DFIG	Double-Fed Induction Generator
EMT	Electromagnetic Transient
ESCR	Effective Short Circuit Ratio
FRT	Fault Ride Through
GIP	Grid Injection Point
GO	Grid Owner
GXP	Grid Exit Point
HVDC	High Voltage Direct Current
IBR	Inverter-based Resource
OEM	Original Equipment Manufacturer
N-1	New Zealand's power system operation standard: all circuits are in service following the unplanned outage of a single network element.
N-1-1 or N-G-1	An extension of the N-1 standard where the power system can handle two consecutive losses, i.e. where a generator, line, or transformer pre-contingency outage is followed by the unplanned loss of a single network element.
POC	Point of Connection
POD	Power Oscillation Damper
PPOs	Principal Performance Obligations
PSS	Power System Stabiliser
RMS	Root Mean Square
SCR	Short Circuit Ratio
SO	System Operator
SMIB	Single Machine Infinite Bus
SSF	System Security Forecast
STATCOM	Static synchronous compensator
SVC	Static Var Compensator
The Code	Electricity Industry Participation Code 2010
TWD	Tail Water Depression

2 Asset Owner Obligations

Your obligations depend on the capacity of your generating asset, the planned location in the grid that the asset is to be connected, and whether the asset has a point of connection to the grid. This section provides guidance on how to determine your point of connection and the applicable obligations and connection study requirements.

Refer to chapter 5 of the *CACTIS* for mandated connection study requirements.

You should discuss and confirm your obligations with the System Operator early on during the commissioning process.

2.1 Point of Connection

Your connection point determines whether you have voltage support obligations or not (see section 2.2).

If you have entered a Part 12 connection agreement with Transpower as Grid Owner, then your generating asset is deemed to have a point of connection to the grid. If you have entered a Part 6 connection agreement with another party, then you are **not** grid connected.

2.2 Obligations for Connection Types

Your generating asset will have different obligations based on its connection type:

- You have **frequency support** and **fault ride through (FRT)** obligations if your generating station has a capacity greater than, or equal to, the threshold mentioned in clause 8.21 (1) of the Code. If your asset's capacity is below the threshold mentioned in Clause 8.21 (1), you may be required by the Electricity Authority to meet some or all of these requirements.
- You have **voltage support** obligations if your generating asset is connected directly to the network.

We have summarised these obligations in Table 1 below for clarity.

Table 1: Obligations Based on Connection Type

Obligation	Generating Station Connection Type		
	Typical Generation Asset (Grid-connected, not Excluded)	Grid-connected Excluded Asset (as per Clause 8.21)	Asset with no Point of Connection to the Grid, but not Excluded
Frequency Support (Clauses 8.17, 8.19)	☑		☑
Voltage Support (Clause 8.23 / Clause 8.23A)	☑	☑	☑
Fault Ride Through (Clause 8.25)	☑		☑

2.3 Study Requirements

Once you know which obligations apply to your particular asset, refer to Table 2 below to identify the specific studies you will need to perform.

Table 2: Connection Study Requirements Based on Obligation

Connection Study (Ctrl+click to go to that study's section)	Obligations		
	Frequency Support	Voltage Support	Fault Ride Through
Power-flow Study	☑	☑	☑
Reactive Power Capability Study		☑	
Frequency Regulation and Tuning Study	☑		
Voltage Regulation and Tuning Study		☑	
Short Circuit Study	☑	☑	☑
Fault Ride Through (FRT) Study			☑
Transient Stability Study	☑	☑	☑

*Note: In addition to the above studies, the System Operator also expects you to complete a **harmonics distortion study** as per the requirements of Transpower as Grid Owner. Ensure you have discussed the scope with them and followed through with that study, then submit the harmonics report as part of your final connection studies report to the System Operator.*

3 General Requirements for Connection Studies

This section contains information and requirements common to all connection studies.

Refer to chapter 5 of the *CACTIS* for mandated connection study requirements.

3.1 Supporting Information from the System Operator

To support you to conduct your connection studies, ensure you access the RMS full network model in DIgSILENT PowerFactory format, provided through the *Electricity Authority's website*.

If you have fault ride through obligations, look the PSCAD Electromagnetic Transients (EMT) network model provided on our *Power System Studies and Modelling* webpage. Additionally, look for the FRT assumptions document for the appropriate grid zone on that webpage.

The FRT assumptions documents contain:

- The *System Security Forecast* (SSF), which includes:
  - a three year load forecast
  - an outline of existing and potential future network issues
  - a list of committed projects for additional generation, transmission, and demand side management in a three year horizon; and
- Information relevant to different connection studies, which could include:
  - the monitored voltage stability zones
  - information required to model any upcoming network developments
  - automatic under-frequency load shedding scheme
  - over-frequency generators tripping scheme
  - protection fault clearing time
  - special protection scheme.

3.2 Connection Studies Report

The connection studies report must follow the template set out in Appendix A. You must provide the following information for your generating asset within the report:

- confirmation that your connection studies are based on the submitted Asset Capability Statement (ACS), including capability curves;
- single line diagrams (including cable collector system, if known, and site layout);
- dynamic models for the generation technology with typical parameter values that adequately represent the generating station's behaviour (see section **Error! Reference source not found.**); and
- distribution-level transformers and other equipment in the network model – only if your generating asset connects to a distribution network.

Note: Following commissioning, if you need to update asset capability information, including parameters in the dynamic model, then you may need to update some of your connection studies. Engage and agree with the System Operator on these as part of the final compliance assessment during the Closeout phase.

You must package all study cases, result files and relevant model libraries used in your connection studies and submit them to the System Operator together with the final connection studies report. The next section provides more guidance.

3.3 Model Preparation

3.3.1 M1 – Connection Study Model

The connection study model for a new generating asset is defined in the *CACTIS* as the **M1 model**.

The M1 model must be developed, parameterised, and submitted in accordance with:

- ***GL-EA-716*** for synchronous generating units, and
- ***GL-EA-1311*** for inverter-based resources (IBRs).

The M1 model need be submitted along side connection study report and in accordance with the applicable CACTIS time frames.

> *Note: For a doubly-fed induction generator (DFIG), modelling requirements may differ. Refer to GL-EA-1311 in the first instance, then contact the System Operator if you require further clarification.*

For cases where the performance of a new generating asset must be assessed in conjunction with models of other generating assets, asset owners must obtain consent from the relevant other asset owner(s) or OEM(s) – through the System Operator, where required – to access the necessary models.

3.3.1.1 M1 Model Parameter Integrity

The final M1 model and connection studies must be conducted and submitted using a single, consistent, final parameter set to be used in the actual control system during the commissioning test.

During the commissioning testing, where it is necessary to adjust control system parameters from the values set in M1 model, such adjustments must not exceed ±5% of the corresponding parameter values.

Where any parameter value is modified beyond ±5% of the corresponding parameter values, the asset owner must repeat some of the connection studies using the updated parameter set.

3.3.2 Network Model Preparation

The M1 model of the new generating asset needs to be integrated to the RMS full network model, the EMT full network model, or the SMIB network model, depending on the studies involved (see section 3.1).

When a connection study is required for embedded generating stations, the asset owner must collect information about the embedded network and incorporate it into the relevant network model.

3.4 Management of Non-compliance

If you identify a shortfall in performance or non-compliant behaviour, you must address and agree these with the System Operator before the commissioning phase commences. A management strategy for any non-compliant behaviour may include:

- recommendations to remove any shortfall in performance to meet the AOPOs and/or the Technical Codes before the end of any commissioning period;
- details of any dispensation applications that have been (or will be) lodged to manage any shortfall in Code obligations;
- details of any equivalence arrangements that have been (or will be) lodged, which, if approved by the System Operator, would help you to achieve compliance wth the Code.

4 Connection Study Types and Requirements

This section describes the different connection studies that you will need to conduct to allow the System Operator to ensure that connecting your new generating asset will not compromise the quality, security or reliability of the New Zealand power system.

Common Study Requirements

To correctly conduct any of the connection studies, you must adhere to all the general requirements mentioned in section 0, along with the requirements listed in the specific studies in this section. The descriptions and specifications build on the mandated requirements in chapter 5 of *CACTIS*.

Use this checklist to help you:

Table 3: General Checklist for Connection Studies

The asset owner has...	Complete?
reviewed and considered the information provided by the System Operator (see section 3.1).	☐
prepared the relevant models as part of each study (see section Error! Reference source not found.) and considered the specifications in the Model Preparation section of each study.	☐
reviewed the relevant study scenarios and prepared study cases according to the specifications in the Study Case Preparation section of each study.	☐
conducted each study taking in consideration the scope, assessment criteria, and expected outcomes.	☐
consulted the System Operator to manage any shortfalls or non-compliances (see section 3.4).	☐
packed all study cases and model libraries with the connection studies report.	☐
prepared the connection studies report using the provided advice and format (see section 3.2 and Appendix A).	☐

4.1 Power-flow Study

This study examines how the power flow changes as a result of the installation of the new generating unit. Its inclusion must not impose any operational constraints that limit either the unit's asset capability or the operation of the power system.

4.1.1 Objectives

Objectives: the study aims to…	**Code Compliance: the study demonstrates…**
▪ **demonstrate the generating station will not overload any equipment;** ▪ **ensure the generating station does not impose operational constraints under normal and outage conditions.** ▪ **determine whether connecting the generating station introduces new credible risks such as risk groups from N-1 or N-1-1 contingencies.**	▪ compliance with Clause 8.22 of Part 8 ▪ compliance with Clauses 2 (1) (a), (b), (c) of Technical Code A ▪ compliance with Clauses 2 (2) (a), (b) of Technical Code A ▪ that your asset's performance will support the System Operator to plan to meet, and meet, its obligations as detailed in the Policy Statement.

4.1.2 Study Case Preparation

Adhere to the following:

- Consider winter peak, summer light and no generation scenarios from wind and solar generating stations in the study vicinity covering a three-year horizon.
- Use hydro generation to balance supply and demand, while geothermal and thermal generation operate as baseload sources.
- Ensure that all generating units are dispatched within the reactive power limits.
- Ensure that SVC and STATCOMs are dispatched up to 75% of their reactive power capacity.
- All voltage at network buses should be within the Code's limits, as stated in Clause 8.22.
- All assets should stay within capability limits before applying a contingency.
- Under extreme light load conditions, switching out transmission circuits to manage pre-contingency voltage is allowed.

Note: If you have performed a Power-flow study as part of the concept assessment of your new generating station (a stage which occurs before the feasibility phase of the commissioning process), then you can include it as part of your connection studies report. This is to avoid repetition and to save cost and time. The study must satisfy the following pre-requisites:

- The study uses the same key parameters as are used in the rest of the connection studies.
- The network has not significantly changed to affect the outcomes of the power-flow study.
- The study meets the relevant study objectives outlined in this document.
- The key findings are summarised in the connection studies report and the full feasibility assessment study is attached in an appendix to the report.

4.1.3 Study Scope

The N-1 and N-1-1 contingency analysis in this study aims to investigate how the new generating unit will impact the loadings of the transmission network and transmission voltages following a contingency. You must apply all credible contingencies to the transmission network in close proximity to the new generating station. These are defined in the Policy Statement and can include:

N-1 Contingencies	N-1-1 Contingencies
the loss of a single: ▪ transmission circuit ▪ interconnecting transformer ▪ generating unit ▪ reactive power compensation device	▪ a planned outage of a transmission circuit and unplanned outage of another circuit ▪ when appropriate, application of similar N-1-1 study methodology on inter-connecting transformers and reactive power compensation devices ▪ if the new generating station is located in Grid Zone 8 or Grid Zone 13, analysis of the N-1 and N-1-1 contingency on the HVDC link.

The study should also consider other credible outage scenarios to ensure any long term outage will not affect the operation of the transmission network and the new generating station.

4.1.4 Assessment Criteria

Your study must meet the following criteria:

Assessment	Criteria
Transmission Circuits Thermal Overload	The new generating station must not cause the overload of any transmission circuits or transformers in close proximity. For contingency analysis, it is appropriate to use: ▪ branch ratings for transmission lines; and ▪ post-contingency 24-hour branch ratings for transformers. Although they are an operational reality, 15-minute offload ratings are not modelled in the RMS full network model project cases. Studies should be conducted to 100% thermal loading of transmission circuits. You should request additional information to include and assess 15-minute offload ratings from the System Operator if the circuit is only marginally overloaded in post-contingency. The extra capability unlocked by the 15-minute offload ratings is unlikely to help if the circuit is heavily overloaded.
Steady State Voltage	The new generating station with a point of connection to the grid must not adversely affect the System Operator’s ability to operate the grid within the nominal grid voltage range.

4.1.5 Study Outcomes

We expect the following outcomes from an analysis of the study’s results:

- a table showing the impact of the new generation on thermal loading and voltages in the region, with any thermal limit and/or voltage limit violations clearly identified;
- identification of any thermal and voltage limit violations that need to be resolved prior to the start of the commissioning phase, to the satisfaction of the System Operator. You should study and clearly state any mitigation measures, such as a special protection schemes, in the final connection studies report.
- identification of potential generator risk groups (a group of generators which would be disconnected by a single contingency) due to the connection of the new generating station; this may be directly due to an outage or indirectly due to a special protection scheme action during normal or outage conditions.

We may accept operational measures to resolve any identified violations if the measures do not cause any limitation to the operation of the power system and nearby connection parties.

4.2 Reactive Power Capability Study

This study examines the new generating station's reactive power capability to regulate the voltage at the POC under all plausible system conditions.

4.2.1 Objectives

Objectives: the study aims to…	**Code Compliance: the study demonstrates…**
▪ assess the generating station's ability to meet the AOPOs while maintaining the voltage at its POC within the normal operating voltage range, and when connected and made available for dispatch by the System Operator. Your generating asset must be capable of importing and exporting minimum reactive power as outlined by the Code. ▪ consider the limits resulting from the physical layout or control system of the generating station, such as over-excitation or under-excitation limiters; ▪ where the connection transformer has an off-load transformer, identify the optimal generator transformer tap position for synchronous generation, or the station transformer tap position for inverter-based resources, to enable the generating station to operate in its full reactive power range under all plausible system conditions. ▪ determine the asset's reactive power capability to regulate the grid voltage at the POC under all plausible system conditions.	▪ compliance with Clause 8.23 or 8.23A of Part 8 ▪ that the performance will support the System Operator to plan to meet, and meet, its obligations in Clause 11.4 of the Policy Statement.

4.2.2 Study Case Preparation

Consider winter peak and summer light-load conditions.

Schedule the new generating station active power output across a representative range of operating levels, including 100%, 50%, and 30% of the station's rated active power output.

Studies must consider applicable control modes (e.g. voltage control, reactive power control, power factor control) using settings consistent with intended operational and commissioning configurations.

Reactive power capability must account for inverter current limits, active–reactive current prioritisation, control saturation, and any internal plant or protection constraints that may restrict reactive power delivery.

Additionally, for inverter-based resources (IBR):

- For partial generation study cases, represent the generating station output by scheduling individual generating units, inverter strings, or aggregated generating units in proportion to the dispatched active power output level.
- Where an aggregated model is used, the aggregation must appropriately reflect collector system effects and their impact on reactive power delivery, as well as the active and reactive power contribution of operating units. Any units or aggregated blocks not contributing to active or reactive power output must be switched off or de-energised in the model.
- For battery energy storage systems (BESS), partial generation study cases must consider both charging, discharging and idle modes. The reactive power capability study must also be undertaken while the BESS is charging at 100%, 50%, and 30% of its rated charging active power.

4.2.3 Study Scope

Perform the study by:

- setting the point of connection (POC) voltage to representative operating values within the allowed voltage range;

- scheduling the generating station reactive power output from minimum to maximum capability at defined active power levels;
- checking station bus voltage, inverter current limits, and collector system constraints to determine maximum reactive power import and export; and
- repeating the assessment under representative post-contingency voltage conditions

4.2.4 Assessment Criteria

The study results must demonstrate compliance with Clause 8.23 or 8.23A of Part 8 of the Code.

4.2.5 Study Outcomes

We expect the following outcomes from the study:

- a table summarising the study results;
- a station reactive power capability curve with the study results plotted to demonstrate that the generating station can meet Code requirement;
- the tap position of the generator transformer or station transformer (for wind and solar generating stations) to be used during commissioning of the new generating station; and
- confirmation whether voltage limits will be violated if the station is dispatched at min or max Mvar during testing.

4.3 Frequency Regulation and Tuning Study

This study helps to ascertain your generating station's ability to responsively and stably control its frequency, supporting the security and quality of New Zealand's power system. The study must only be conducted after your generating station's frequency/speed control system design has been finalised.

4.3.1 Part A: Frequency Controller Performance Study

4.3.1.1 Objective

Objectives: the study aims to…	**Code Compliance: the study demonstrates…**

▪ assess the frequency regulation performance of the new generating station in response to grid disturbances, ensuring that the new station supports frequency management and does not lead to:
  ▪ constraints of the power system operation; nor
  ▪ an increase in the need to procure frequency reserve to maintain system frequency within the stated limits; nor
  ▪ a change to the present frequency management strategy
▪ assess the stability of the speed/frequency controller to regulate system frequency;
▪ determine a suitable speed/frequency droop setting for the station; and
▪ determine suitable control system parameter values to be used for commissioning prior to fine tuning at the generating station site.
	▪ compliance with Clauses 8.17 and 8.19 of Part 8
	▪ compliance with Clauses 5 (1) and 5 (3) of Technical Code A
	▪ that your generating asset's performance will support the System Operator to plan to meet, and meet, its obligations as detailed in the Policy Statement.

4.3.1.2 Study Case Preparation

Adhere to the following:

- Consider winter peak, summer light-load, and full-generation scenarios for wind, solar, and BESS generating stations in the study vicinity.
- Use hydro generation to balance supply and demand, while geothermal and thermal generation operate as baseload sources.
- Dispatch hydro generation at 80% to provide sufficient frequency reserve so that the biggest single contingency will keep island frequency above 48 Hz (if a generating unit contingency were applied).
- You can add automatic interruptible load shedding up to 100MW to the North Island, if necessary.
- Include automatic under-frequency load shedding in relevant study cases, using the percentage set out in the Code, distributed evenly across both the North and the South Islands.
- Request over-frequency generators tripping scheme from the System Operator (this generally applies to North Island geothermal and South Island hydro generating assets).
- HVDC is not modelled dynamically in the RMS full network model cases and will not contribute to frequency reserve.

4.3.1.3 Study Scope

Carry out frequency disturbance-based analysis to assess the dynamic performance of the station under all system conditions.

Tuning and Pre-study Stability Check

- Prior to system studies or following any required control retuning, control system models must demonstrate adequate stability margins using Nyquist or equivalent frequency-domain analysis methods. The pre-study stability margins provide a minimum robustness check. Control system tuning must achieve stability margins equivalent to a gain margin of 1.7–4 (unitless) and a phase margin of 30°–45°.
- For inverter-based resources, this requirement applies to relevant control loops (e.g. PLL, active and reactive power, voltage, and current control), using analysis methods appropriate to the modelling approach.

After tuning, use the following disturbances to demonstrate performance in a time domain simulation:

North Island Disturbances	South Island Disturbances

▪ step response test (MW and frequency ref);
▪ standard under-frequency injection test;
▪ disconnection of the island's largest units;
▪ disconnection of the HVDC bipole;
▪ 200 MW or less step decrease in demand to cause the island frequency to rise, but stay below 51 Hz; and
▪ ramp the North Island demand by 100 MW at ramp rate of:
  ▪ 10 MW per second
  ▪ 1 MW per second
  ▪ 0.5 MW per second.
	▪ step response test (MW and frequency ref);
	▪ standard under-frequency injection test;
	▪ disconnection of the island's largest units;
	▪ disconnection of the HVDC bipole;
	▪ 100 MW or less step decrease in demand to cause the island frequency to rise, but stay below 51 Hz; and
	▪ ramp the South Island demand by 50 MW at ramp rate of:
	  ▪ 10 MW per second
	  ▪ 1 MW per second
	  ▪ 0.5 MW per second.

If the generating station might operate while being islanded due to an N-1-1 contingency, its performance under such islanded conditions should be thoroughly evaluated.

4.3.1.4 Assessment Criteria

The generating station must demonstrate stable frequency response and compliance with Code requirements. In particular, each generating unit must:

- respond in a stable manner to system frequency disturbances;
- increase active power output in response to a decrease in system frequency, up to the unit's maximum available power;
- reduce active power output in response to an increase in system frequency, provided this does not require operation below the technical minimum;
- maintain at least its pre-disturbance active power output for a frequency reduction of up to 2 Hz;
- meet the droop setting requirements specified in Clause 5(1)(c)(ii) of Technical Code A; and
- remain connected and not trip within the frequency ranges specified in Clauses 8.19(1) and 8.19(3) of the Code for the North and South Islands, respectively.

Any over-frequency trip settings must be clearly stated in the ACS and represented in the study models.

4.3.1.5 Study Outcomes

We expect the following outcomes from the study:

- The speed or frequency controller responds in a stable manner;
- Time-domain simulation plots are included to demonstrate the speed/frequency controller performance;
- Frequency-domain results (e.g. Nyquist, Bode, or equivalent plots) are provided to demonstrate adequate stability margins; and
- A confirmed set of frequency control system parameter values to be used for commissioning prior to fine tuning of the speed/frequency controller at the generating station site.

4.3.2 Part B: Frequency Controller Priority Study

4.3.2.1 Objective

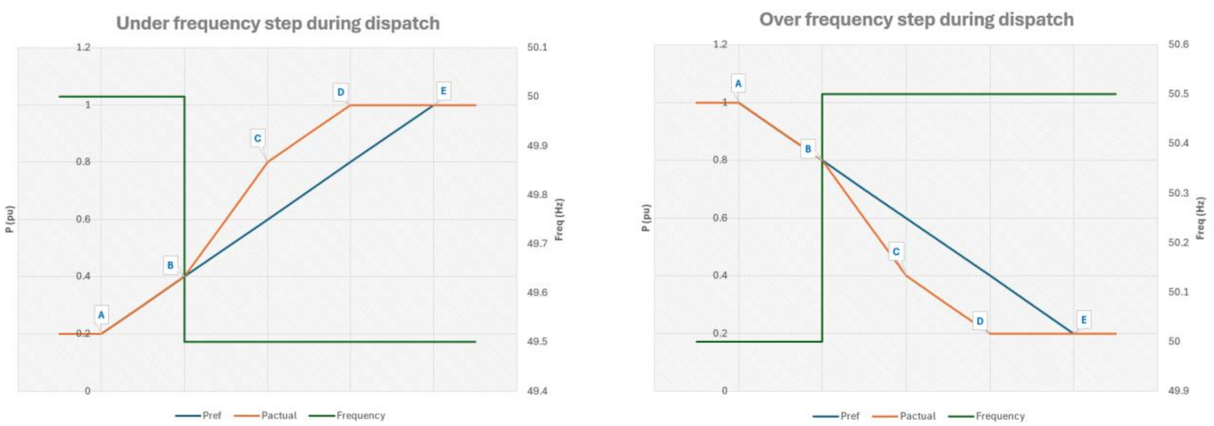
To demonstrate that the generating plant frequency control system is correctly tuned and that frequency control action takes precedence over dispatch commands during system frequency disturbances.

4.3.2.2 Study Approach

Assess the frequency response using a time-domain simulation in which:

- Step 1: Initialisation and dispatch
  - The plant shall be initialised at steady-state at:
    - Frequency = 50 Hz
    - Active power output = 0.2 pu
  - The plant shall then be dispatched upwards (Dispatch set point = 1 pu) using the configured dispatch ramp rate.
- Step 2: Frequency disturbance during dispatch
  - During the dispatch ramp (target range: 0.4–0.5 pu active power), a frequency disturbance shall be applied:
  - Negative step change (under-frequency) of -1% relative to nominal frequency.
  - During the disturbance , the plant shall respond with an active power ramp consistent with its defined frequency response ramp. The response shall continue until the active power output reaches the pre-disturbance MW operating level plus the droop-based MW contribution corresponding to the frequency deviation (see figure below).
- Step 3: After Droop based response
  - The plant shall revert to dispatch control
  - Active power shall continue to follow the pre-disturbance ramp rate
- Step 4 : Repeat the simulation for over frequency step
  - Perform separate simulations for positive step change (over-frequency) of +1% relative to nominal frequency when the plant is dispatched down from 1pu to 0.2pu.
    Please refer to figure below to understand test and expected response.

Frequency controller priority testing



Pref: Active power reference from PPC to inverter
Pactual: Measured inverter active power output

4.3.2.3 Expected Behaviour

- Expected response
  - Pref trajectory
    - A–B–E: Active power setpoint follows the dispatch ramp rate
  - Pactual trajectory
    - A–B: Active power follows dispatch ramp rate under normal operation

- B–C: Active power follows frequency response ramp rate and the settling point (point C) shall be as per combined effect of:
  - ongoing dispatch ramp, and
  - droop-based frequency response
- C–D: Once the droop response is fully delivered, active power continues at dispatch ramp rate

4.3.2.4 Assessment Outcome

Studies should confirm that:

- Frequency control parameters (including deadband, droop and response rate) are appropriately configured;
- Frequency control action is prioritised over dispatch during frequency disturbances; and
- The plant provides a stable and predictable contribution to system frequency control under all tested operating conditions.

4.4 Voltage Regulation and Tuning Study

This study helps to ascertain your generating station's ability to contribute to both fault current and voltage regulation without degrading voltage quality. The study must only be conducted after your generating station's voltage control system design has been finalised, and before the station connects to the power system.

4.4.1 Objectives

Objectives: the study aims to…	Code Compliance: the study demonstrates…
▪ assess the voltage regulation performance of the new generating station in response to grid disturbances, ensuring that the new connection supports system performance and does not: ▪ constrain power system operation; ▪ affect the voltage regulation capability in the vicinity of the station; ▪ degrade the damping of the power system voltage, resulting in oscillation (a potential impact of excitation limiter controls or power system stabiliser control); nor ▪ cause oscillation or instability in equipment operation, e.g. hunting tap-changing or repeated capacitor bank switching; ▪ assess the dynamic responses of the voltage controller to regulate system voltage during and following a power system fault or disturbance; ▪ assess the response of the over- and under-excitation limiters; ▪ assess and tune the power system stabiliser (PSS) or power oscillation damper (POD), to damp plant power oscillation and improve the damping of network-wide oscillatory modes; and ▪ determine suitable control system parameter values to be used for commissioning prior to fine tuning at the generating station site.	▪ compliance with Clauses 8.22 and 8.23/8.23A of Part 8 ▪ compliance with Clauses 5 (2) and 5 (3) of Technical Code A ▪ that your generating asset's performance will support the System Operator to plan to meet, and meet, its obligations as detailed in the Policy Statement.

4.4.2 Study Case Preparation

Adhere to the following:

- Consider winter peak, summer light-load, and peak-generation and no-generation scenarios for wind, solar, and BESS generating stations in the study vicinity.
- Use hydro generation to balance supply and demand, while geothermal and thermal generation operate as baseload sources
- Dispatch all generators within their reactive power limits.
- Dispatch SVC and STATCOM up to 75% of its reactive power capacity.
- Schedule all 220 kV and 110 kV bus voltages between 1 and 1.06 p.u. prior to applying contingencies.
- Schedule all 66 kV bus voltages between 1 and 1.025 p.u. prior to applying contingencies.
- Include relevant N-1-1 contingencies identified in the SSF where these materially affect voltage at the point of connection.

4.4.3 Study Scope and Assessment Criteria

Perform the voltage regulation study below first, then the PSS/POD tuning if your generating asset has that equipment.

4.4.3.1 Voltage Regulation

Study Scope

Carry out disturbance-based analysis to assess the dynamic performance of the station under all system conditions.

Start this study only after completing the reactive power capability study (Section 4.2). Use the agreed reactive capability limits and fixed transformer tap positions from that study.

In your study, consider the following disturbances:

- step changes in voltage reference and reactive power reference;
- disconnection of nearby network elements that produce a voltage step at the point of connection that is sufficient to assess the effectiveness of the tuning;
- disconnection of reactive power devices within the station (e.g. STATCOM, SVC, capacitor banks); and
- disconnection of the HVDC bipole.

Additionally, for synchronous generating units:

- verify correct operation of over-excitation and under-excitation limiters by adjusting excitation and applying a step disturbance that drives the operating point into the limiter region; and
- ensure that the response remains stable, well-damped, and free of sustained oscillations or adverse control interactions.

For IBRs:

- verify correct operation of voltage, reactive power, current, and protection limiters (including current saturation, voltage limits, and priority logic) by applying step disturbances or set-point changes that drive the controller into the relevant limiting regions;
- confirm appropriate interaction between voltage control, reactive power control, and current limiting functions under these conditions; and
- ensure that the response remains stable, well-damped, and free of sustained oscillations, limit cycling, or adverse control interactions.

Assessment Criteria

The generating station must demonstrate stable voltage control and compliance with Code requirements. In particular, each generating unit must:

- respond in a stable manner to voltage disturbances at the point of connection;
- regulate voltage in accordance with the agreed control mode (e.g. voltage control, reactive power control, or droop);
- increase reactive power output in response to a decrease in voltage, up to the unit's reactive capability limits;
- reduce reactive power output in response to an increase in voltage, within reactive capability limits;
- maintain continuous operation without instability, limit cycling, or sustained oscillations across the normal steady-state voltage operating range;
- operate within agreed voltage droop, deadband, and response settings; and
- remain connected and not trip for voltage conditions within the continuous operating ranges specified in the Code and applicable performance standards.

4.4.3.2 Power System Stabiliser (PSS) /Power Oscillation Damper (POD) Tuning

Study Scope

When tuning your PSS or POD or any custom made damping controller, you must consider the following:

- Get the latest system frequency response data from the System Operator or *dynamic stability reports* dynamic stability reports to identify oscillation modes without the PSS/POD.
- Cover all relevant system conditions, including N-1 and N-1-1 transmission outages.
- Test PSS/POD performance by applying step changes to generator terminal voltage, exciter field voltage, current, or relevant IBR control setpoints.
- Run modal (eigenvalue) analysis with PSS/POD ON and OFF. Show improved damping ratio and eigenvalue shift with PSS/POD ON. Include participation factor and mode shape plots.
- Provide Bode plots (PSS/POD OFF) to identify phase lag at the dominant oscillation frequency and show how lead-lag filters or equivalent compensation blocks are tuned, aiming for phase mismatch within ±30°.

- Use root locus plots to show how controller gain affects stability and to identify the critical gain. Set operational gain between one-third and one-half of the critical gain.
- Explicitly report damping ratios and frequencies for all relevant modes, before and after tuning.
- Perform time-domain (RMS) simulations with voltage step tests to verify improved damping with PSS/POD ON.
- Use PMU data or dynamic stability reports to target inter-area modes where possible.

Assessment Criteria

- The damping controller (PSS/POD or equivalent) must provide a compensated frequency response so that the relevant control loop phase does not exceed ±30° from 0.1 Hz to 10 Hz, as demonstrated by Bode or eigenvalue plots.
- Output limits must be at least ±5% of the synchronous asset's terminal voltage, or for IBRs, within agreed current or voltage control saturation limits.
- Set the controller gain margin to at least 6 dB and no more than 10 dB.
- Set the washout time constant (or equivalent filter/bandwidth setting) as low as possible, provided the phase compensation requirement is still met.
- Plots and analysis results must be included as evidence in the study report.

4.4.4 Study Outcomes

We expect the following outcomes from the study:

- The voltage controller must respond in a stable manner.
- The responses must meet the performance criteria.
- Include time-domain simulation plots to demonstrate the voltage controller performance.
- Demonstrate effectiveness of PSS/POD using:
  - Bode plots showing phase compensation and gain margin.
  - Excitation response plots with the generating unit connected, both with and without PSS/POD in service.
  - Time-domain plots showing step responses of terminal voltage, field voltage, field current, power, PSS/POD output, AVR output (with and without PSS/POD).
- A confirmed set of voltage control system parameters including PSS/POD parameters to be used for commissioning prior to fine tuning at the generating station site.

4.5 Short Circuit Study

This study determines the Effective Short Circuit Ratio (ESCR) at the point of connection. You must document the impact of your asset's short circuit current for protection operation, equipment ratings, and wider power system design.

4.5.1 Objective

The study aims to identify the short circuit level at the site, which will help determine:

- The ESCR across different network conditions;
- the parameters of the voltage controller (if used in FRT study); and
- the overload capability of the inverter/STATCOM, if applicable.

4.5.2 Study Case Preparation

To study the impacts of the new generating station during different system operating conditions, adhere to the following:

- Consider winter peak, summer light-load, and peak-generation and no-generation scenarios for wind, solar, and BESS generating stations in the study vicinity.
- Switch synchronous generating units out of service if they are not generating.
- For wind, solar, and BESS generation, it is acceptable to leave the full station in service at reduced output levels.

4.5.3 Study Scope

For ESCR calculations, there are several short-circuit calculations methods available such as IEC or ANSI. However, the System Operator prefers the use of the complete short-circuit method in PowerFactory for ESCR calculation. Once you have chosen a method, clearly state it in the connection study report.

In your study, consider the following system conditions:

- peak and light load conditions;
- full intact system and relevant power system re-configuration (as advised by the System Operator);
- N-1 and N-1-1 outage scenario; and
- the application of a three phase zero impedance fault.

Use the lowest short circuit level after a contingency has been applied to determine the ESCR at the POC.

4.5.3.1 Classic ESCR Calculation

Classic ESCR is suitable for strong networks where the system impedance and short circuit levels are stable, and synchronous machines dominate the generation mix. It provides a quick screening metric for system strength and is used to assess the ability of the network to support conventional generator connections.

This method assumes linear network behavior and neglects the impact of fast-acting controls or converter dynamics, making it less accurate for weak grids or networks with significant inverter-based resources.

Classic ESCR is defined by:

$$ESCR = \frac{SCCi - Qi}{Pi}$$

where:

$SCCi$: short circuit level (MVA) at the POC prior to connecting the generating station

Qi: shunt compensation at POC bus

Pi: Rated power of the new asset (MVA)

4.5.3.2 Dynamic ESCR Calculation

Dynamic ESCR is applied in scenarios where system strength is influenced by non-linear controls, converter interactions, or complex network topologies—such as grids with high penetration of wind, solar, or battery energy storage systems. It uses EMT or RMS simulations to capture the true response of the system to faults, including the effects of protection, control logic, and network configuration changes.

Dynamic ESCR ($ESCR_{dyn}$) is defined by:

$$ESCRdyn = \frac{Dynamic\ SCCi\ - Qi}{Pi}$$

where:

$Dynamic\ SCCi$:	Measured[1] short circuit level (MVA) at the POC prior to connecting the generating station
Qi:	shunt compensation at POC bus
Pi:	Rated power of the new asset (MVA)

4.5.4 Assessment Criteria

Results and findings must be documented and presented as part of the comprehensive connection study report.

4.5.5 Study outcomes

We expect that the study will record:

- short circuit fault level for buses in close vicinity to the new generating station (provide short circuit level in kA and MVA); and
- the maximum and minimum ESCR including network scenario that results in minimum ESCR at POC.

If needed, use these ESCR values to set up the SMIB.

[1] Measured as follows:

- Simulate 3-phase fault at POC (new asset disconnected)
- Measure fault MVA [$\sqrt{3}$ **x** $\mathbf{V_{poc}}$ **x** $\mathbf{I_{fault}}$]

  $\mathbf{I_{fault}}$: Initial symmetrical fault current measured during the first cycle after fault application
- Subtract shunt compensation (MVar), if any

4.6 Fault Ride Through (FRT) Study

This study aims to assess the capability of the new generating asset to remain connected and maintain stable operation during grid disturbances, including voltage depressions, short-circuit faults, and other transient events. The System Operator provides a regional fault ride through (FRT) assumptions document (see section 3.1) which details information that you must consider when performing this study.

Conduct your FRT studies according to the rated capacity of your generating asset:

Generating Station MW Output	Required FRT Studies*
≥10 and <30 MW	▪ RMS studies in this section (4.6) **and** the SMIB EMT studies in Appendix B.
≥30 MW	▪ RMS and EMT studies in this section (4.6).
* With synchronous generating assets, conduct the FRT study using RMS simulations only. With IBRs, conduct the FRT study using both RMS and EMT simulations.	

4.6.1 Objective

The study aims to demonstrate your generating asset's compliance with fault ride through requirements in Clauses 8.25 A to D of the Code. These specify different voltage requirements depending on where your generating asset is connected – either the North Island's power system, or the South Island's, or in the vicinity of Haywards or Benmore.

4.6.2 Study Case Preparation

Prepare your study cases to cover the requirements provided in your FRT assumptions document.

4.6.3 Study Scope

Adhere to the study scope provided in the FRT assumptions document.

Typically, an FRT study consists of:

- RMS domain studies using the RMS network model published *by the Electricity Authority* to identify worst-case fault performance. These studies shall capture conditions associated with weak grid operation, high levels of IBR penetration, and potential control interactions.

- Targeted EMT domain studies using detailed network and control models to assess the worst-case scenarios identified from RMS analysis, where fast control dynamics, protection operation, or converter interactions materially affect FRT performance. EMT studies typically consider:
  - at least two active power operating levels at the point of connection (e.g. high and low MW output);
  - relevant fault types (e.g. single-phase-to-ground, phase-to-phase, and three-phase faults as applicable);
  - up to three fault locations, including electrically close and remote faults from the point of connection; and
  - up to three system short-circuit strength conditions representative of strong, intermediate, and weak grid operation.

- Additional EMT assessments must include, where relevant:
  - post-fault voltage recovery and active/reactive power recovery behaviour;
  - correct operation of inverter current limits, fault current injection logic, and control mode transitions during and after faults;
  - protection interaction and non-maloperation during fault and clearance;
  - sensitivity to fault clearing times, including delayed fault clearance; and

    - system response following single-shot and automatic reclosing events (if applicable).

During studies

If any control system settings are modified during Fault Ride-Through (FRT) studies, asset owners must notify the System Operator and repeat the FRT studies using the revised settings.

Post-commissioning

If any control system settings are modified during or after commissioning, asset owners must notify the System Operator and repeat the FRT studies using the revised settings.

To demonstrate Code-compliant FRT performance, you should also apply the fault types listed in Table 4.

- Fault F1 and F4
    - Fault types F1 and F4 shall be applied at the POC and represent balanced and unbalanced zero-impedance faults, respectively.
- Fault F2, F3
    - Fault types F2 and F3 shall be applied as balanced faults at the medium-voltage (MV) busbar (33 kV or lower), reflecting longer fault-clearing times typically associated with distribution feeder faults.
    - Where retained voltages at the POC cannot be achieved, equivalent impedance faults may be applied at remote 220 kV or 110 kV buses, provided no transmission circuit trips.
    - For impedance fault representations:
        - only a reactive impedance shall be used (zero fault resistance)
        - the selected impedance value, fault location, and technical justification shall be clearly documented in the study report.

Table 4: Fault Types for the North and South Islands

Fault type ID	Retained voltage at the POC (% of nominal)	Duration of the fault (sec)
F1	0	0.12
F2	0.35	0.48
F3	0.76	2.98
F4	0	0.12

4.6.3.1 Generating Stations Connected to Grid Zone 8 (Wellington) and Grid Zone 13 (Otago)

Stations connecting in Grid Zones 8 and 13 require additional studies to assess your generating asset's capability in riding through:

Requirement	How to Simulate
1. the specific over-voltage FRT curves (provided in Code Clause 8.25A) at the Haywards or Benmore 220 kV bus resulting from bipole power interruption (which can be a trip or temporary interruption)	Disconnect the HVDC bipole at high electrical power transfer. The studies should cover both high north and high south flow. The generating asset should remain stable and electrically connected. DC can be reconnected beyond the time of the Transient Over Voltage envelope.
2. multiple voltage sags resulting from HVDC fault recovery behaviour, e.g. commutation failure.	Request specific fault data to inject from the System Operator.

This additional study scope for Grid Zone 8 and 13-connected generating assets are designed to analyse the effect of HVDC-related system interaction, specifically:

- a bipole trip;
- a rectifier fault which interrupts the bipole operation and then restores it (which can be represented by a bipole trip); and
- HVDC commutation failure.

The System Operator can provide recorded system event data to demonstrate the expected voltage behaviour for the above DC events.

4.6.4 Studies involving Models of Other Generating Assets – System Operator Support

For cases where the performance of a new generating asset must be assessed in conjunction with models of other generating assets, the asset owner may adopt one of the following approaches:

Option 1: Asset Owner-led	Option 2: System Operator-led
Obtain explicit consent from the relevant asset owner or OEM for the use of their models. Access such models through the System Operator where required, noting that: ▪ **Models are typically provided in encrypted or compiled form.** ▪ **Model access may be restricted to defined study purposes only.** ▪ **Modification of third-party models is not permitted.**	Request the System Operator to conduct EMT studies on your behalf. This is suitable in cases where: ▪ Third-party models are not available to the asset owner, or ▪ Model confidentiality, encryption, or licensing constraints prevent direct access. Under this option: ▪ The System Operator will use secure, internally-held models. ▪ Study scope, assumptions, and deliverables will be agreed prior to commencement. ▪ Only study results and conclusions will be shared with the asset owner; third-party models will not be released. ▪ Where the EMT studies identify any non-compliance or deficiencies (including FRT performance), the System Operator shall coordinate with the relevant asset owner and OEM to define and assess corrective actions. **Note:** with this option, there might be a cost-recovery required, and timelines must be agreed with the System Operator ahead of the studies.

4.6.5 Assessment Criteria

Your generating asset must:

- remain stable and electrically connected when the grid voltage is within the applicable no-trip zone;
- provide reactive current to the maximum of its capability to support voltage during the fault, and the appropriate reactive current following the fault;
- ensure its reactive current delivery meets Code Clause 8.25B (1); and
- ensure its active power recovery meets Code Clause 8.25B (2).

The reactive current support can come from the generating units or the dynamic reactive power compensation devices within your generation station.

4.6.6 Study Outcomes

We expect the following outcomes from your study:

- The generating units meet all the assessment criteria whilst riding through faults.
- Your study document fully discusses the fault ride through strategies.
- You identify and explain any non-compliant, or potentially non-compliant, behaviour.

- You confirm that no protection or control settings at the generating station would result in a breach of the fault ride through requirements.

Note: You must report any equipment in your generating station that will trip within the applicable no-trip zone, and/or result in the tripping of another generating asset.

4.7 Transient Stability Study

This study examines a new generating asset's ability to withstand severe and credible contingencies, then return to stable operation. Conduct the your transient stability study depending on the type of generating asset: synchronous or IBR, as below.

4.7.1 Synchronous Generating Assets

4.7.1.1 Objective

The study aims to demonstrate that your new generating asset can remain stable and connected after the removal of a three phase bus fault at the POC. Your new generating asset must be evaluated for its Critical Fault Clearing Time (CFCT), the maximum fault duration for which generation remains transiently stable.

4.7.1.2 Study Case Preparation

Adhere to the following:

- Use the RMS full network model.
- Ensure that your generating asset is absorbing and producing reactive power close to its reactive power capability limits.
- Ensure that your generating asset is generating at its maximum MW output.

4.7.1.3 Study Scope

To determine the CFCT, apply a three-phase fault with the following characteristics at the POC high-voltage bus:

- fault clearing time of 120 ms; and
- remove a circuit connected to the faulted bus.

Proceed to increase fault clearing time until your generation asset does not return a stable operating point close to the starting condition.

Conduct this study with a fully intact system and relavant power system re-configurations by disconnecting a circuit that is connected directly to the station.

4.7.1.4 Assessment Criteria

The CFCT determined from this study must be longer than the protection fault clearing time for the POC bus and transmission circuits connected to your generating asset. You must obtain the fault clearing time from the Grid Owner or distributor, as applicable.

4.7.1.5 Study Outcomes

We expect the following outcomes from your study:

- The CFCT is longer than the maximum fault clearing time, demonstrating that the generating units can ride through all faults on the transmission circuit and the POC bus.
- Any non-compliant, or potentially non-compliant, behaviour is identified and explained.
- You confirm whether protection or control settings at the generating station would result in a breach of the fault ride through requirements.

4.7.2 Inverter-based Resources

4.7.2.1 Objective

For IBRs, classical transient stability concepts such as loss of synchronism are not applicable. Instead, 'transient stability' refers to post-fault voltage, power recovery performance and fault-induced control instability.

The objective of this assessment is to demonstrate that the IBR remains connected and operates in a stable and controlled manner during and after fault clearance, without delayed recovery, adverse control interactions, or protection maloperation.

4.7.2.2 Study Case Preparation

Perform the assessment by:

- Applying unbalanced faults at the POC and selected remote buses representative of credible transmission and distribution-level disturbances.
- Assessing multiple system strength conditions, including strong and weak grid cases representative of expected ESCR conditions at the POC.
- Varying fault clearing time, starting from the nominal protection clearing time and increasing to identify sensitivity of post-fault voltage and control recovery, noting any loss of control stability, blocking, or delayed recovery.

Conduct your assessment using RMS analysis. Undertake an EMT analysis only where fast control dynamics, current limiting, or protection behaviour are identified as materially influencing the response and cannot be adequately represented in RMS studies.

4.7.2.3 Assessment Criteria

In addition to FRT compliance, the IBR must satisfy the following post-fault performance criteria:

- Voltage recovery

  The IBR restores voltage at and around the POC following fault clearance without prolonged delay, stalled recovery, or secondary voltage depression caused by current saturation or control lock-in.
  Example: under weak system strength conditions, current limiting shall not result in sustained voltage depression or delayed voltage recovery at the POC.

- Active and reactive power recovery

  The IBR restores active and reactive power in a controlled and stable manner following fault clearance, with ramp rates and control mode prioritisation with configured limits and without excessive overshoot or oscillatory behaviour.
  Example: under weak system strength conditions, post-fault active power ramp-up shall not delay voltage recovery or induce oscillations.

- Inverter control stability

  The inverter control system remains stable following fault clearance, with no sustained oscillations, repeated control resets, blocking, or unintended protection operation.
  Example: under weak system strength conditions, PLL, voltage, and current control signals shall exhibit well-damped settling without growing oscillations.

4.7.2.4 Study Outcomes

We expect your study report to include:

- identification of the most limiting fault scenarios and operating conditions;
- evidence of stable inverter control during and after fault clearance;
- demonstration of compliant voltage and power recovery behaviour;
- identification and explanation of any marginal or non-compliant behaviour; and
- confirmation of whether any inverter control or protection settings constrain fault-induced performance.

Appendix A. Connection Studies Report Template

You must electronically submit your connection studies files (including test cases, scenarios and models) along with your connection studies report, which must be in Adobe Portable Document format (PDF) or Word Document format (DOCX).

The report must include:

- **Executive summary:** to summarise the studies, findings, non-compliance (if any), and recommendations;
- **Background:** to describe the new generating asset's location and all relevant station information used in the connection studies; and
- **Discussion of studies:** to include detailed discussion on the findings, mitigation measures and recommendations for the following studies:
  - Power-flow
  - Reactive power capability
  - Frequency regulation and tuning
  - Voltage regulation and tuning
  - Short circuit
  - Fault ride through
  - Transient stability
- **Findings and recommedations**: to summarise the key mitigating actions that the asset owner will take in order to comply with their obligations and ensure reliable results.
- **Appendix**: to include:
  - Reactive power capability curves with all the limits plotted
  - Control block diagram, including a table to show the parameter values used in the studies for:
  - Speed/frequency controller
  - Voltage controller including station controller, if applicable
  - PSS/POD
  - Limiters
  - Simulation results

Appendix B. FRT Studies for 10-30 MW Generating Assets

B.1 Objective

These FRT studies aim to assess the capability of the generating asset to remain connected and maintain stable operation during grid disturbances, including voltage depressions, short-circuit faults, and other transient events. The assessment includes validation of key control functions such as voltage support, reactive current injection, and frequency response under faulted conditions.

This section defines a limited and targeted scope of EMT studies, intended to minimise the burden of conducting extensive EMT analysis for smaller generating assets (typically 10–30 MW). Undertake the EMT studies in this section only after RMS studies are completed and the most problamatic scenario have been identified.

B.2 Study Setup

Set up your PSCAD (or as applicable) case for a SMIB test as follows:

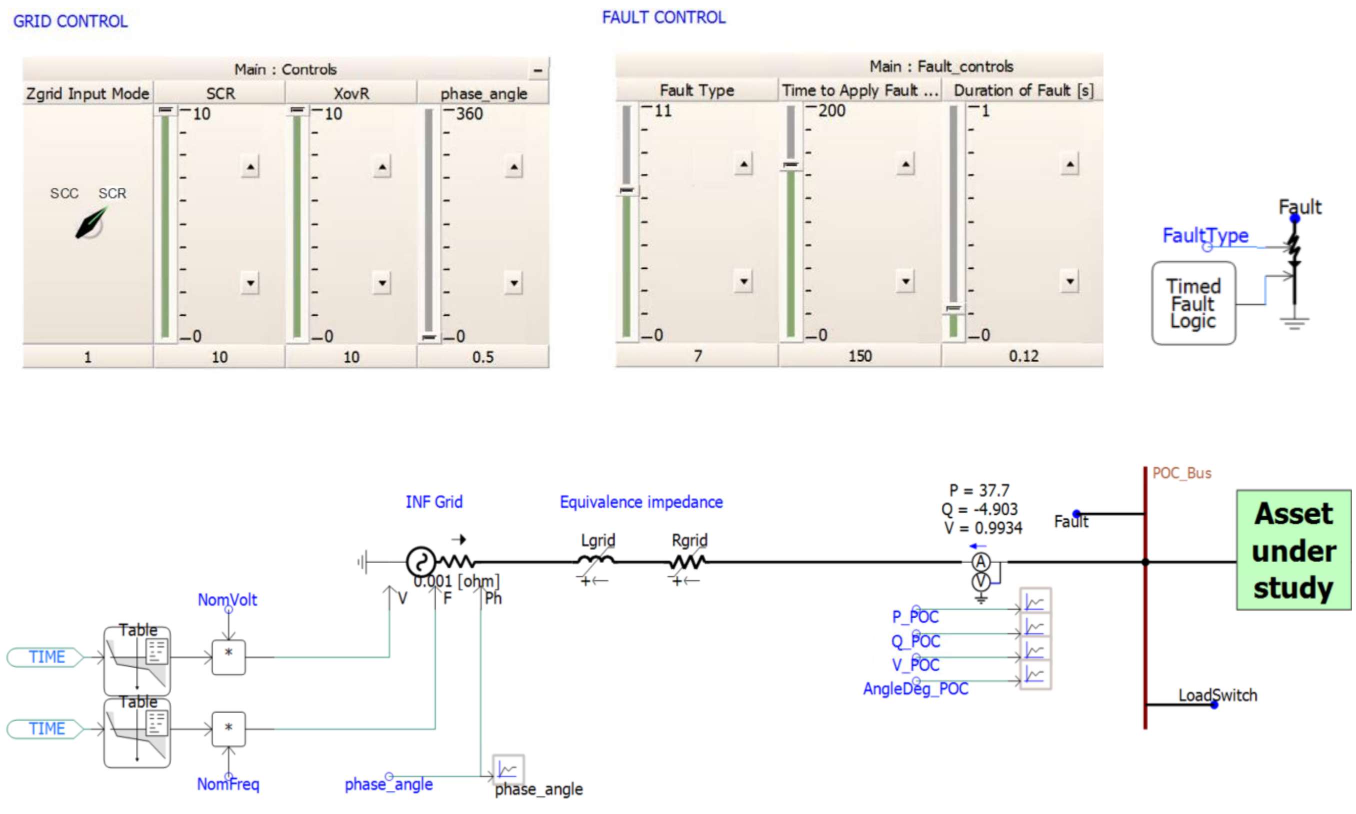


Figure 2: SMIB Test Setup

B.3 Test Types

B.3.1 No Disturbance

Objective: To validate steady-state stability, controller equilibrium, and numerical robustness of the generating asset model under undisturbed operating conditions. Confirm that the model reaches and maintains a stable operating point with no unintended control drift, limit cycling, or numerical instability.

Test 1: No disturbance for 60 seconds.

B.3.2 Step Change

Objective: Verify that the control system responds stably to step changes and settles without sustained oscillations or instability.

Mode: Voltage control enabled (V_setpoint = 1.0 pu)

Test Matrix:

Sr no	SCR	P (pu)	Grid Voltage Step
1	POC*	1.0	±3% step in voltage
2	POC*	0.5	±2% step in frequency

POC* = minimum SCR as identified by short circuit studies

B.3.3 Fault Response

Objective: To validate capability of the new generating asset to remain connected and maintain stable operation during grid disturbances.

Mode: Voltage control enabled (V_setpoint = 1.0 pu), or intended control mode.

Test Matrix:

Sr no	SCR	P (pu)	Fault / contingency
1	3	1.0	3ph-G , 120ms**, zero impedance fault @ POC_BUS
2	POC*	1.0	3ph-G , 120ms**, zero impedance fault @ POC_BUS
3	3	1.0	2ph-G , 120ms**, impedance fault @ POC_BUS
4	POC*	1.0	2ph-G , 120ms**, impedance fault @ POC_BUS
5	POC*	1.0	± 25degree phase angle jump in grid voltage
6	Switch	1.0	SCR switch from 3 → POC* + 20 second delay + POC*→3
7	POC*	1.0	3ph-G , 120ms**, impedance fault @ POC_BUS
8	POC*	1.0	2ph-G , 120ms**, impedance fault @ POC_BUS
9	POC*	1.0	3ph-G , 120ms**, zero impedance fault @ POC_BUS + SCR switch from 3 → POC* + 20 second delay + POC*→3
10	3	-0.2#	3ph-G , 120ms**, zero impedance fault @ POC_BUS
11	3	-0.5#	3ph-G , 120ms**, zero impedance fault @ POC_BUS
12	POC*	-0.2#	3ph-G , 120ms**, zero impedance fault @ POC_BUS
13	POC*	-0.5#	3ph-G , 120ms**, zero impedance fault @ POC_BUS

* minimum ESCR as identified by short circuit studies
** or protection clearing time
# charging rate only applicable to BESS

5 Document Information

5.1 Metadata

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