Generation Fault Ride Through

Consultation Paper

Submissions close: 5pm on 6 October 2015

August 2015

899660-10

Executive summary

The Electricity Authority (Authority) has reviewed the asset owner performance obligations in the Electricity Industry Participation Code 2010 (Code) that require generating units not disconnected directly by protection systems to remain connected during transmission faults. The review found that generator fault ride through will become an issue if a significant amount of synchronous generation was displaced by wind generation that contained limited fault ride through capability.

The power system is designed and operated so that generation disconnected because of major transmission faults will not produce under-frequency events large enough to cause widespread loss of supply.

The two types of major transmission faults that have the greatest effect on the power system are:

(a) 220 kV transmission faults that cause large-scale voltage dips as low as zero volts at the point of the fault

(b) high voltage direct current (HVDC) bi-pole trips or rapid runbacks that cause high over-voltages on the 220 kV buses at HVDC converter stations at Haywards and Benmore, and on the transmission systems around these stations.

Most synchronous generating units remain stable through the transient voltage disturbances that accompany major transmission faults. However, the ability of wind generation to ride through faults and provide voltage support during voltage disturbances varies. Wind generating units are mostly non-synchronous[1] and their capability to ride through faults depends on the type of technology used.

The amount of wind generation is increasing, and this is starting to affect grid security. Without appropriate performance standards, the system operator must make broad assumptions about the fault ride through capability of wind generation. Ultimately, this will lead the system operator to carry more reserve to ensure the power system remains secure in the event of major transmission faults.

Many international regulators have introduced fault ride through standards to manage the effect of changes in the mix of generation connected to their grids. Wind turbine manufacturers have responded to new standards by increasing the ability of certain classes of plant to ride through faults and support recovery of grid voltage after faults.

The Authority and the system operator have investigated the current and future dynamic voltage performance of the New Zealand power system. The investigations have led to the Authority developing proposed standards for fault ride through to suit

[1] Generating units on a.c. power systems are either synchronous or non-synchronous. The output frequency of synchronous units is exactly determined by rotor speed, while output frequency of non-synchronous units is slightly lower than the frequency determined by rotor speed.

conditions in the North and South Island power systems. The Authority proposes to add the recommended standards to the Code.

The standards would require that any new generating units:

(a) remain transiently stable and connected to the power system without tripping while system voltage remains within a defined under and overvoltage envelope following a fault on the transmission system

(b) maintain power output during and following a transmission fault to avoid complete loss of power injection into the grid

(c) provide the maximum possible reactive current injection during a fault to minimise voltage dip and support recovery of system voltage following a fault.

The Authority has considered a market-based approach to applying the proposed fault ride through standards, but prefers the approach used in part 8 of the Code for asset owner performance obligations. The dispensations provisions form part of this approach and a specific cost allocation for dispensations from the proposed fault ride through standards is included in the Authority’s 2015/16 work programme.

This consultation paper focuses on the effect of Pole 3 of the HVDC link on over voltage fault ride through requirements in parts of the country near Haywards and Benmore. This was a significant issue raised by Transpower in its submission on an earlier consultation paper published in February 2011.

Proposed changes to the Code are included in Appendix A.

Contents

Tables

Figures

1. Your feedback is welcome

1.1 What this paper is about

1.1.1 The Authority wishes to consult with participants and persons that the Authority thinks are likely to be substantially affected by a proposed change to the Code. The change would require generators to ensure their assets remain connected to the system during transmission faults.

1.1.2 The objective of the Code amendment proposal is to specify dynamic voltage performance obligations for all new generation connected to the New Zealand grid. The obligations are expressed in the form of fault ride through requirements intended to ensure there is no loss of stability during and immediately after transmission faults.

1.1.3 The system operator would be responsible for operating the power system within such requirements, to ensure that it is able to meet its principal performance obligations.

1.1.4 Section 39(1)(c) of the Electricity Industry Act 2010 (Act) requires the Authority to consult on any proposed amendment to the Code and the regulatory statement. Section 39(2) provides that the regulatory statement must include a statement of the objectives of the proposed amendment, an evaluation of the costs and benefits of the proposed amendment, and an evaluation of alternative means of achieving the objectives of the proposed amendment. The regulatory statement is set out in part 3 of this paper.

1.1.5 The proposed amendment is attached as Appendix A.

1.1.6 The Authority invites submissions on the regulatory statement and the proposed amendment, including drafting comments.

1.2 How to make a submission

1.2.1 The Authority is likely to make your submission available to the public on the Authority's website. If necessary, please indicate any documents attached in support of your submission and any information you have provided on a confidential basis. However, you should be aware that all information you provide is subject to the Official Information Act 1982.

1.2.2 The Authority prefers to receive submissions in electronic format (Microsoft Word) in the format shown in Appendix A. Submissions in electronic form should be emailed to submissions@ea.govt.nz with "Consultation Paper – Generation Fault Ride Through" in the subject line.

1.2.3 Do not send hard copies of submissions to the Authority unless it is not possible to do so electronically. If you cannot or do not wish to send your submission electronically, you should post one hard copy of the submission to either of the addresses provided below or you can fax it to 04 460 8879. You can call 04 460 8860 if you have any questions.

<u>Postal address</u>

Submissions
Electricity Authority
PO Box 10041
Wellington 6143

<u>Physical address</u>

Submissions
Electricity Authority
Level 7, ASB Bank Tower
2 Hunter Street
Wellington

1.3 Deadline for receiving a submission

1.3.1 Submissions should be received by **5pm** on **6 October 2015**. Please note that late submissions are unlikely to be considered. The Authority will acknowledge receipt of all submissions electronically. Please contact the Submissions' Administrator if you do not receive electronic acknowledgement of your submission within two business days.

2. Issue the Authority would like to address

2.1 The current arrangements

2.1.1 The New Zealand power system regularly experiences single and three phase a.c. transmission faults that cause large system voltage dips near the fault locations. Generating units across the system experience varying reductions in voltage, depending on distance from the fault.

2.1.2 Similarly, the power system experiences trips of the HVDC link periodically. Generating units across the system experience large system over voltages depending on distance from the HVDC converter stations, and the power transfer level on the link.

2.1.3 Sympathetic tripping of non-faulted generating units during transmission faults may lead to voltage or frequency instability and, in extreme cases, cascade failure of the power system. To maintain a secure system, it is important that non-faulted generating units remain connected and ride through periods of voltage and frequency disturbances during and following faults.

2.1.4 The Code includes a limited set of steady state voltage-related performance obligations for asset owners to ensure their generating units remain connected during voltages disturbances. The obligations for asset owners include:

(a) grid connected generators must be operable over a range of grid voltages (± 10% for 220 kV and 110 kV, and ± 5% for 66 kV and 50 kV) (clause 8.22(2))

(b) protection systems must operate to selectively disconnect the minimum amount of plant and preserve power system stability during faults (clause 4(4)(a)(ii) of technical code A of schedule 8.3)

(c) voltage control systems on grid connected generators must be designed and have settings to support the system operator in meeting the Principal Performance Obligations, eg, to avoid cascade failure during voltage excursions (clause 5(1)(a)(i) of technical code A of schedule 8.3)

(d) grid connected generators must provide reactive power capability over a range of grid voltages to support the system operator in maintaining grid voltage within acceptable limits and secondly, to support the system operator in maintaining voltage stability on the grid (clause 8.23).

2.2 Code does not require assets to remain stable and connected during voltage disturbances

2.2.1 The Code does not require that grid connected generators are specified and installed with adequate capability to ride though transmission faults. There are no system specific dynamic voltage performance obligations in the Code that would ensure this. System security has remained adequate while generation on the power system has been predominantly synchronous. Most synchronous generating units have in-built capability to ride through transient voltage disturbances and remain connected.

2.2.2 However, generation is changing with non-synchronous generation connecting in increasing quantities. Wind turbines use semiconductor-based voltage control equipment that is sensitive to voltage disturbances.

2.2.3 Consequently, the system operator cannot rely on this type of plant remaining connected during widespread voltage disturbances. At times, it must procure additional instantaneous reserve to cover the risk of this plant tripping in sympathy during disturbances.

2.3 Why the Authority is addressing these issues now

2.3.1 There is currently 688 MW of wind generation capacity connected to the grid or embedded in distribution networks. The output from this generation accounts for about 6% of electricity consumed in New Zealand.

2.3.2 With the gradual displacement of synchronous generation by wind generation, the Authority is concerned that the current arrangements are inadequate. If not improved, cost increases passed through to consumers will arise from:

(a) increased quantities of instantaneous reserve required to protect against the loss of injection from non-faulted generating plant

(b) restrictions on the types of generation development in some geographical regions

(c) increased risk of consumer disconnection due to gradual erosion of system stability.

2.3.3 The Authority first proposed changes to the Code in February 2011 to address these concerns. Submitters raised an issue about that proposal concerning over voltages that arise when the HVDC link trips. The Authority and the system operator have completed work to address that issue and the Authority is now consulting on an updated the proposal.

Question 1	Do you agree the issues the Authority has identified are worthy of attention?

3. Authority consulted on this issue in 2011

3.1 Submissions received

3.1.1 The Authority first consulted on a proposal to add fault ride through standards to the Code in February 2011. The Generation Fault Ride Through Consultation Paper[2] for the February 2011 consultation is attached as Appendix D.

3.1.2 The following 12 parties made submissions on the Authority's proposal:

Table 1: Submissions Received

Submitter	Category
Contact Energy Ltd (Contact)	Generating company
Genesis Energy Ltd (Genesis)	Generating company
Major Energy Users Group (MEUG)	Major users
Meridian Energy limited (Meridian)	Generating company
NZ Wind Energy Association (NZWEA)	Representative body
Philip Wong Too	Individual
Repower Australia Pty Ltd	Wind turbine manufacturer
Todd Energy (Todd)	Major user and generating company
Transpower NZ Ltd (Transpower)	Grid owner and system operator
Trustpower Ltd (Trustpower)	Generating company
Vestas NZ Wind Technology Ltd (Vestas)	Wind turbine manufacturer
Windflow Technology Ltd (Windflow)	Wind turbine manufacturer

2 The paper is also available at: http://www.ea.govt.nz/our-work/consultations/pso-cq/generation-fault-ride-through/

3.2 Submitter support for addressing security risks divided

3.2.1 Six submitters supported the Authority’s overall objective to address the increasing security risks as new forms of generation are added to the system.

3.2.2 Meridian, NZWEA, Todd, and Transpower agreed that a fault ride through standard is required. Trustpower and Windflow provided qualified support.

3.2.3 Transpower raised a concern about over voltages in the lower North Island and a region around Benmore. The grid owner identified that known HVDC events involving Pole 3 would create over voltages in these areas more onerous than those calculated for the proposed fault ride through standards. In Transpower’s view, a more stringent fault ride through standard should be imposed in these regions.

3.2.4 Contact, NZWEA, and Genesis questioned whether the results of the system operator’s studies would remain valid following the commissioning of Pole 3. They assumed (incorrectly – see section 2.6) that less stringent under voltage standards may be required after the commissioning of Pole 3.

3.2.5 Vestas was opposed to fault ride through standards being added to the Code on the basis that such standards would impose additional costs on wind generation projects in locations where the requirements might not be necessary.

3.2.6 All submitters who commented on whether the proposed fault ride through standards should exclude generating stations smaller than 30 MW supported the use of this de minimis. Transpower noted the need for the system operator to be able to request the Authority, on a case by case basis, to require any excluded generators to comply with the fault ride through requirements.

3.2.7 All submitters other than Transpower agreed that the proposed fault ride through standards should not apply to all existing generating plant. The Authority subsequently clarified with Transpower that the proposed standards require assets that are currently compliant with the standards to remain so. On that basis, Transpower accepted that the standards should not apply to all existing generating plant.

3.2.8 The basis for not applying the proposed fault ride through standards to existing generating plant is outlined in section 3.3 below.

3.2.9 All submitters supported the Authority’s proposal that separate standards should be used in each of the North and South Islands. Submitters agreed a combined standard could lead to increased compliance costs.

3.2.10 Two submitters did not agree that the Wind Generation Investigation Project's (WGIP)[3] wind generation scenarios represented an appropriate range of wind penetration levels to test the sensitivity of the net present value (NPV) analysis. The Authority accepts that the WGIP scenarios were not developed as forecasts of potential wind energy development, but they represented previously developed benchmarks. Their use allows the NPV analysis to be correlated with findings from the WGIP.

3.2.11 A number of submitters suggested alternative input assumptions that could be used in the NPV analysis, some of which would result in increased economic benefits while others would decrease the benefits. The wind turbine manufacturers challenged the timeframe over which the Authority assumed that fault ride through technology would become a universally adopted standard as more and more jurisdictions adopt fault ride through standards. Setting aside views on suggested improvements to the NPV analysis, only one submitter challenged the Authority's finding that the proposed fault ride through standards produce an overall positive economic benefit.

3.2.12 Opinion was divided on whether the fault ride through standards should be implemented immediately or triggered at a future date by the actual level of wind generation penetration.[4]

3.2.13 Concern was expressed about the effect the standards may have on new plant investments already in development but not yet commissioned. As there is now only one wind farm under construction (at Flat Hill in Bluff), this issue can be addressed in the timing of the effective date of the Authority's proposal.

3.2.14 Submitters made a number of suggested improvements to the wording of the proposed Code amendment. Suggested improvements have been considered and changes adopted in the wording of the original proposal, where appropriate.

3.3 Application to existing generating stations

3.3.1 The proposed fault ride through standards are an exacerbators pay approach to mitigating system costs that are forecast to increase over time. Under an exacerbators pay approach, all parties whose actions or inactions lead to cost increases should pay for mitigating those costs.

3.3.2 Owners of existing generating stations that are not compliant with the proposed fault ride through standards are already contributing to

[3] The Electricity Commission and system operator carried out this strategic investigation to assess the likely future effect of wind generation development in New Zealand.

[4] The original cost-benefit analysis indicated that the minimum level of wind capacity needed to ensure a positive net benefit was 950 MW in the North Island and 350 MW in the South Island.

increased system costs to a limited extent. In a small number of trading periods, the HVDC extended contingent event risk binds due to high northward transfer levels. During these trading periods, the system operator purchases additional instantaneous reserve to cover the risk of North Island wind farms tripping as a result of the HVDC bipole tripping.

3.3.3 The Authority estimates the annual cost of the additional quantities of reserve to be in the order of $500,000. Wind farms alone contribute to the need for this instantaneous reserve but do not pay any share of the cost

3.3.4 In addition, wind farms in both islands can trip for a.c. transmission faults and contribute to the need for instantaneous reserve, but don't currently pay a share of the instantaneous reserve availability costs.

3.3.5 Accordingly, existing generating stations that don't meet the proposed standards and are unable to ride through transmission faults currently impose costs on others by:

(a) not paying a share of the instantaneous reserve costs

(b) increasing the quantity of instantaneous reserve required when the HVDC extended contingent event risk is binding.

3.3.6 The proposed fault ride through standards should apply equally to both new and existing generating stations to ensure that all exacerbators who increase system costs pay for those costs. However, if the standards were applied in this way, owners of non-compliant wind farms could apply for dispensations[5] from full compliance.

3.3.7 The system operator must grant a dispensation to an asset owner who has a non-compliant asset if the system operator can continue to meet its principal performance obligations, despite the non-compliance (clause 8.31 of the Code). As the system operator is able to meet its principal performance obligations when existing wind generating stations are dispatched, any requests for dispensations from the fault ride through standards would likely be granted by the system operator.

3.3.8 The dispensation provisions in the Code require the system operator to allocate costs arising from dispensations but these provisions have little practical effect. The system operator is unable to readily identify and calculate the marginal cost imposed on others by dispensations.

3.3.9 In one exceptional case, costs arising from dispensations from generator under frequency performance obligations are allocated according to a methodology prescribed in the Code.

3.3.10 A similar approach could be used for estimating and allocating additional instantaneous reserve costs arising from dispensations from fault ride standards. Such a cost allocation would require the system operator and

[5] The dispensation regime is part of the asset owner performance obligation framework in part 8 of the Code.

clearing manager to make significant changes to the market systems software.

3.3.11 The Authority recommends that the fault ride through standards apply to both new and existing generating stations. This would ensure that the costs identified in paragraph 3.3.5(b) are correctly allocated to all exacerbators.

3.3.12 The Authority recognises that supporting provisions would be required in part 8 of the Code to correctly allocate the costs of dispensations from the fault ride through standards to dispensation holders. The Authority's 2015/16 work programme includes a project to carry out a fundamental review of the instantaneous reserve event charge and cost allocation. This work includes a review of instantaneous reserve cost allocation to existing wind farms[6] and a dispensation cost allocation for fault ride through can be incorporated into this project.

3.3.13 Allocating the costs as part of the fault ride through proposal would result in overlapping scope with the review project and potentially incur unnecessary costs for changes to the market systems software that are reworked at a later date.

3.4 Pole 2 and Pole 3 modelling assumptions

3.4.1 One issue raised by several submitters was that the full effect of Pole 3 had not been taken into account in the fault ride through analysis. Some submitters, other than Transpower, incorrectly assumed that Pole 3 would be able to provide voltage support for the loss of Pole 2 and thereby lessen the requirement for the proposed transient under voltage ride through standard. This is not the case.

3.4.2 The system operator originally assessed the effect of the loss of either Pole 2 or Pole 3, up to maximum at risk transfer level of 700 MW. The analysis was carried out on an n-1 basis, consistent the approach that was applied for faults on the a.c. network.

3.4.3 The Authority set out the modelling approach for the original studies in paragraph 2.4.5 of the Generation Fault Ride Through Consultation Paper.

[6] At present, wind farms do not receive an allocation for instantaneous reserve costs because the capacity of individual wind turbines is small. Under clause 8.59 of the Code, generating units smaller than 60 MW are considered too small to contribute to the need for instantaneous reserve because they do not cause system events. This is true of individual wind turbines, but not of complete wind farms.

3.5 Transpower's view is that generators must remain connected through a 1200 MW HVDC trip

3.5.1 Transpower's view is that the fault ride through standards should be set at a level to prevent loss of generation resulting from a 1200 MW HVDC bipole trip. This represents a change to the original objective of the standards.

3.5.2 The original objective of the fault ride through standards was that it be consistent with the contingent event approach incorporated in system operator's security policy.[7] The power system is planned under the Grid Reliability Standards and operated under the security policy so that a single contingent event will not cause widespread customer loss of supply. On this basis, the fault ride through standards were designed around the single worst a.c. or d.c. contingency.

3.5.3 A substantive issue raised by Transpower was that the fault ride through standards should require generation to remain connected following an HVDC bipole trip (an extended contingent event) up to a transfer level of 1200 MW.

3.5.4 In response to Transpower's submission, the system operator has completed a number of new studies to evaluate the over voltages resulting from a bipole trip at a transfer level of up to 1200 MW. A report documenting the studies is attached as Appendix F

3.5.5 The system operator now recommends that a transient over voltage standard be applied nationally consisting of the following two separate components:

(a) A minimum absolute voltage standard consisting of 1.2 per unit[8] (p.u.) for 2 seconds, 1.15 p.u. for the following 4 seconds, and thereafter the steady state limit set in the Code of 1.1 p.u.

(b) A ratio-based transient over voltage standard to account for high transient over voltages that occur at Haywards and Benmore as a result of a 1200 MW HVDC bi-pole trip. These over voltages decrease with distance from Haywards and Benmore, and the ratio-based standard takes this effect into account.

3.5.6 The Authority recognises that the potential loss of generation as a result of a full HVDC bipole trip increases the quantity of instantaneous reserve required to cover the HVDC bipole transfer risk, when it is the binding risk. The risk is likely to be binding at times when supply conditions are tight and when instantaneous reserve prices are high.

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[7] Chapter 1 of the Policy Statement incorporated by reference in the Code.

[8] Refers to the per unit system, used in power system analysis to express system quantities as fractions of a defined base unit quality. In the context of this paper, per unit refers to the ratio of grid line to line voltage to its base quantity of 220 kV or 110 kV, as applicable.

3.5.7 A bipole trip at a transfer level of 1200 MW causes a significantly greater transient over voltage in areas near Haywards and Benmore than the maximum level of 1.23 per unit (p.u.) proposed in the Authority's first consultation paper.

3.5.8 The system operator now recommends that a transient over voltage standard be applied nationally consisting of the following two separate components:

(a) A minimum absolute voltage standard consisting of 1.2 p.u. for 2 seconds, 1.15 p.u. for the following 4 seconds, and thereafter the steady state limit set on the Code of 1.1 p.u.

(b) A ratio-based transient over voltage standard to account for high transient over voltages that occur at Haywards and Benmore as a result of a 1200 MW HVDC bi-pole trip. These over voltages decrease with distance from Haywards and Benmore, and the ratio-based standard takes this effect into account.

3.5.9 The system operator does not recommend changes to the original transient under voltage standards for the North and South Islands.

3.5.10 The system operator's report (attached as Appendix F) gives specifications for the ratio-based standard.

4. Regulatory Statement for the proposed amendment

4.1 Objectives of the proposed fault ride through standards

4.1.1 Increasing amounts of non-synchronous generation, principally wind, raises the risk of cascade failure as a result of major transmission faults. In turn this raises the risk of cascade failure of the system. As generation changes, there is growing need to maintain a minimum level of dynamic voltage performance on the grid.

4.1.2 The objective of the proposed amendment is to ensure that the system operator can continue to meet its principal performance obligation to avoid cascade failure arising from voltage excursions during transmission faults.[9]

4.1.3 The Authority has assessed the proposed amendment against the Authority's statutory objective in section 4.5 below.

4.1.4 The Authority has completed a quantitative assessment of the net benefits of proposed amendment as outlined in section 4.3 below.

Question 2	Do you agree with the objectives of the proposed amendment? If not, why not?

4.2 The proposed Code amendment

4.2.1 The proposed amendment would add a set of dynamic voltage performance obligations to the Code, which would require asset owners to ensure their assets remain stable and connected to the grid during transient system disturbances.

4.2.2 The drafting of the proposed Code amendment is included in Appendix A.

Application

4.2.3 The Authority proposes that the fault ride through standards apply to generating stations that export 30 MW or more to a local network or the grid. Tripping of a group of stations smaller than 30 MW within a region as a result of a transmission fault would have limited effect on the dynamic

9 Clause 7.2 of the Code - The **principal performance obligations** of the **system operator** are**—**
(a) to act as a **reasonable and prudent system operator** with the objective of **dispatching assets** made available in a manner that avoids the cascade failure of **assets** resulting in the loss of **demand** and arising from—
(i) frequency or voltage excursions; or…

performance of the grid. This approach is consistent with the application of a 30 MW de minimis to obligations in the Code for generators to support frequency in the normal band and to support frequency in under frequency events.

4.2.4 The Authority proposes that the fault ride through standards apply to both new and existing generating plant. Note that this differs from the application proposed in the February 2011 consultation. The approach recommended for existing generating plant not able to comply with the proposed fault ride through standards is detailed in section 3.3 .

4.3 The benefits of the proposed Code amendment are expected to outweigh the costs

Benefits

4.3.1 The primary benefit of the proposed fault ride through standards arises from the avoided cost of purchasing additional under frequency reserve. If the current arrangements (as described in paragraph 2.1.4) are not changed, additional costs will arise over time from increased quantities of under frequency reserve required to be procured. When the total output of wind generation exceeds the (other) largest contingent event risk, wind generation will become the risk setter and determine the quantity under frequency reserve required to be purchased.

4.3.2 The proposed fault ride through standards have a secondary benefit in preventing the gradual deterioration in the security of the power system. Without fault ride through standards, there is an increasing risk of consumer disconnection as a result of sympathetic tripping of non-faulted generating units during transmission faults.

4.3.3 As changes in risk are difficult to determine, the Authority has not quantitatively assessed the value of this benefit. The analysis below indicates a positive net benefit without including any security related benefits.

Costs

4.3.4 The costs associated with the proposed fault ride through standard arise from additional costs faced by generating companies to meet the proposed fault ride through standards. Only owners of non-synchronous generators, the type of plant predominantly used in wind farms, would face additional costs. These costs arise in improving the capability of voltage and reactive power control equipment associated with wind farms. By comparison, synchronous generators have the inherent capability to meet the proposed standards at no additional cost.

Wind generation development scenarios

4.3.5 The cost-benefit assessment is sensitive to assumptions made about the rate of development of wind generation. In the February 2011 consultation paper, the Authority made use of three of the wind generation development scenarios created for the studies carried out under the wind generation investigation project.[10]

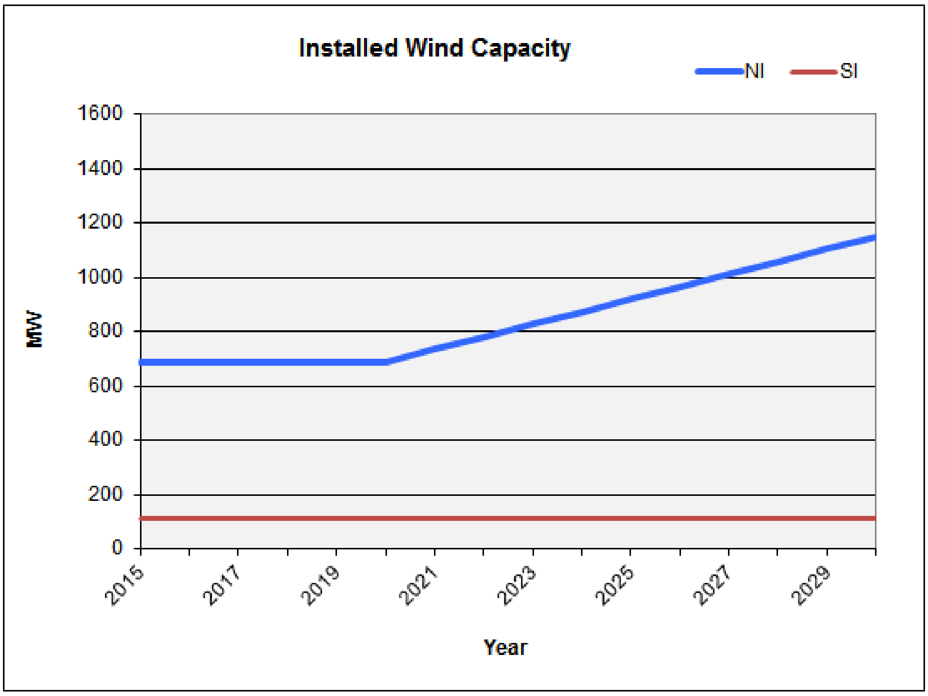
4.3.6 The assessment was based on separate North and South Island instantaneous reserve markets, and wind penetration levels ramping up from base levels in 2010 to the scenario maxima by 2020. The Authority has updated the 2011 assessment (see below) with two changes:

(a) flatter load growth (and hence slower rates of wind generation development)[11]

(b) an assumption that the proposed full national market for instantaneous reserve has been introduced (not currently implemented, but represents a more conservative scenario).

4.3.7 The wind generation development scenarios used in the cost-benefit assessment are shown in Figures 1, 2, and 3. The scenarios are updated versions of those used in the 2011 consultation taking into account slower than predicted rates of development.

Figure 1: Wind scenario A (moderate, concentrated North Island)



[10] This project studied the wider power system and electricity market implications of additional wind generation and how to enable the development of wind generation on a level playing field with other generation sources.

[11] Refer to New Zealand's Energy Outlook, 2013, Ministry of Business, Innovation & Employment.

Figure 2: Wind scenario B (moderate, diversified across NZ)

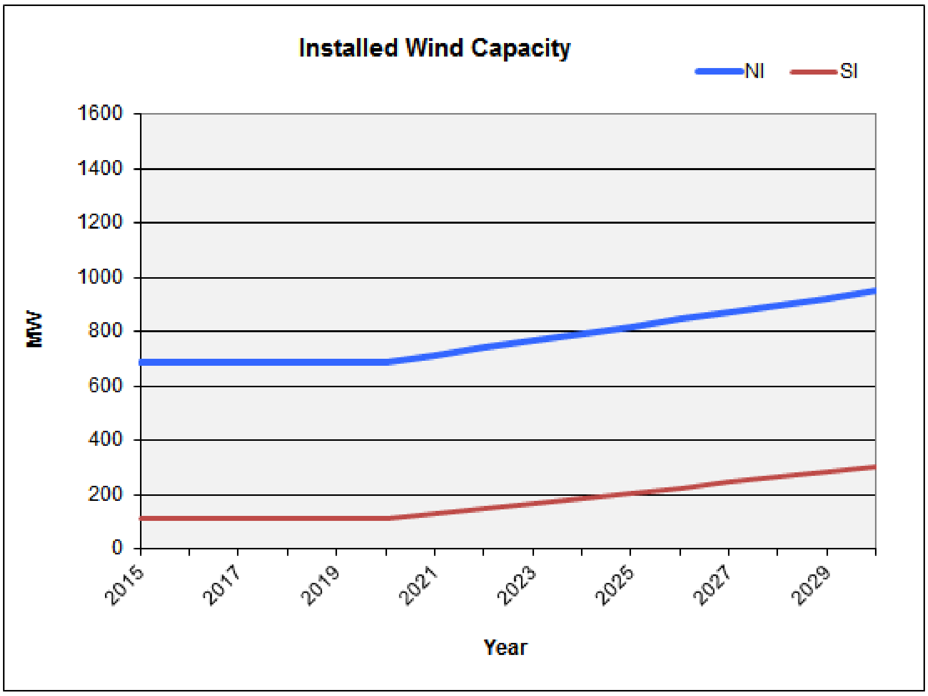
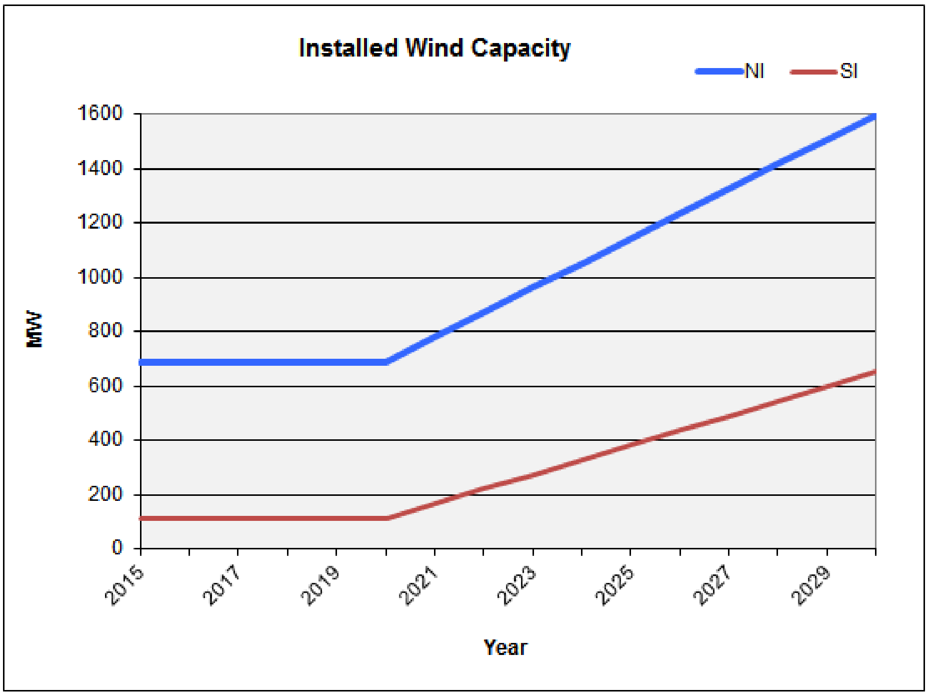


Figure 3: Wind scenario C (high, diversified across NZ)



Other input assumptions

4.3.8 The other input assumptions used in the cost-benefit assessment are set out in Table 2, Table 3, and Table 4.

Table 2: Input assumptions used to calculate costs

Input Assumptions for Costs	North Island	South Island
2015 base year installed wind generation capacity[12]	688 MW	112 MW
Wind generation capacity factor	41%	41%
Average national contingent event risk excluding wind	350 MW	
Wind turbine total installed cost per MW	$3 m	$3 m
Increase in turbine cost to meet fault ride through standard	1.25%	1.25%

Table 3: Input assumptions used to calculate benefits

Input Assumptions for Benefits	North Island	South Island
Fast instantaneous reserve (FIR) required to cover 1 MW of wind turbine risk as a national contingent event (CE) risk	Both Islands 0.9 MW	
Sustained instantaneous reserve (SIR) required to cover 1 MW of wind turbine risk as a national CE risk	Both Islands 1 MW	
FIR required to cover 1 MW of wind turbine risk as additional HVDC extended contingent event (ECE) risk	0.8 MW	0.8 MW
SIR required to cover 1 MW of wind turbine risk as an additional HVDC ECE risk	1 MW	1 MW
Average cost of FIR per MWh procured nationally for CE risk	Both Islands $2.18	
Average cost of SIR per MWh procured	Both Islands	

12 Refer to the list of operating and planned wind generating stations in Appendix C.

Input Assumptions for Benefits	North Island	South Island
nationally for CE risk	$1.74	
Average cost of FIR per MWh procured when the HVDC ECE is binding	$8.28	$3.30
Average cost of SIR procured when the HVDC ECE is binding	$1.19	$1.55
Percentage of trading periods when HVDC ECE is binding for north transfer	3.3%	-
Percentage of trading periods when HVDC ECE is binding for south transfer	-	0.4%

Table 4: Discounted cash flow parameters

Discounted Cash Flow	Parameter
Discount rate sensitivity	4% - 8%
Discount period	15 years

4.3.9 Increased wind turbine costs are calculated as 1.25% of installed capital costs and are assumed to ramp down to 0% over 10 years. The basis of this assumption is that compliance costs will decline over time as technology that is fault ride through compliant becomes a standard feature of grid connected wind turbines.

4.3.10 HVDC link faults impose over voltages simultaneously in both islands, risking wind generation close to Haywards and Benmore. When the HVDC bipole trips, reserve cannot be transferred from one island to the other in a national market for instantaneous reserve. As a result, wind generation close to Haywards must be covered for HVDC faults by instantaneous reserve sourced in the North Island. Similarly, wind generation close to Benmore must be covered for HVDC faults by instantaneous reserve sourced in the South Island.

4.3.11 Because a.c. faults impose under voltages in the faulted island only, they do not cause loss of wind generation in the non-faulted island. It is assumed that the loss of wind generation for a.c. faults can be covered by instantaneous reserve sourced nationally.

4.3.12 The cost-benefit analysis considers the quantity of instantaneous reserve required to cover:

(a) the loss of wind generation for either North Island a.c. faults or South Island a.c. faults, whichever quantity is greater, plus

(b) the loss of wind generation for HVDC faults.

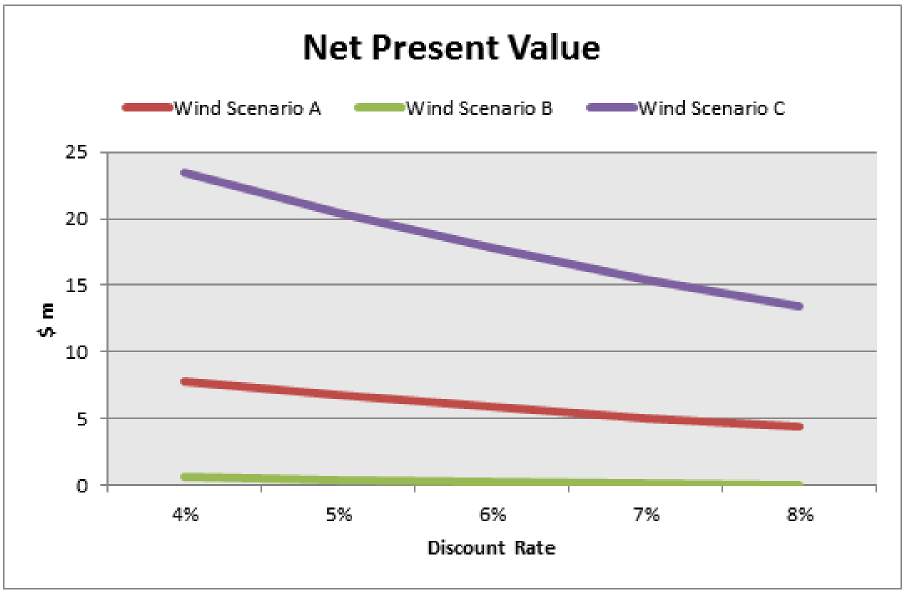
4.3.13 Instantaneous reserve costs for HVDC faults arise only when the HVDC ECE risk is binding and must be purchased separately in each island. The costs are estimated by taking the percentage of trading periods when the HVDC ECE risk was found to be binding in 2014. No allowance has been made for the effect that increasing levels of wind generation have on the number of binding trading periods.

4.3.14 Purchasing of additional reserve to cover wind turbine risk is likely to put upward pressure on the market price. The analysis uses an average price approach that produces a more conservative estimate of benefits.

Net present value analysis

4.3.15 Figure 4 below summarises the Authority's cost-benefit assessment of the proposed fault ride through standards. Net present values (NPV) were calculated using the input assumptions in Table 2 for each of the three wind penetration scenarios.

Figure 4: Net present value variation with wind penetration level and discount rate



4.3.16 The assessment indicates that the proposed fault ride through standards would have positive net benefits if the ultimate level of wind development were to the levels forecast in scenarios A or C. Scenario B represents the threshold of wind development where benefits still exceed costs.

4.3.17 The net benefits assessed in 2011 were as follows (using a 7% discount rate):

(a) scenario A: $21.5 million

(b) scenario B: ($0.5 million)

(c) Scenario C: $98 million

4.3.18 Slower than predicted rates of wind generation development and the introduction of a national market for instantaneous reserve mean that the assessed net benefits for scenarios A and C are now lower than they were when assessed in 2011. The net benefits are still positive for these scenarios, while scenario B remains the threshold of wind development at which costs and benefits are nearly equal.

4.3.19 The Authority considers the probability of wind development exceeding the threshold represented by scenario B in the next 10 years to be reasonably high. Scenario B levels of wind development would be exceeded if only a third of the 1672 MW of farm projects currently consented were completed within the next 10 years.

Question 3	Do you agree the benefits of the proposed amendment outweigh its costs?

4.4 The Authority identified three other ways to address the objectives

4.4.1 The Authority identified three other ways to address the objectives of the proposed fault ride through standards:

(a) option A - fault ride through rights auction

(b) option B - fault ride through performance based on the combined requirements of the system operator's North and South Island proposals

(c) option C - fault ride through performance obligations based on a standard that matches the requirements already developed in other international grid codes.

Option A – Fault ride through rights auction

4.4.2 This option substitutes the dispensation provisions in the Code (associated with the asset owner performance obligations) with auctioned rights for the dispatch of plant with no fault ride through capability. The auction reserve price would be set at the estimated cost of additional instantaneous reserve required to cover the risk represented by the rights.

4.4.3 An approach of this type would require the system operator and the Authority to assess:

(a) the maximum MW quantity of rights that could be auctioned

(b) the threshold of performance below which rights are required, i.e. the proposed fault ride through standards

(c) the reserve price for the rights

(d) the period of time over which the rights would be granted.

4.4.4 The maximum MW quantity of rights is a limit beyond which the system operator could not meet its principal performance objectives. No new rights could be issued above the maximum as over-providers could not compensate for under-providers.

4.4.5 The main advantage of an auctioned rights approach is that no generator can gain a competitive advantage over any other. By comparison, dispensations are granted on a ‘first come first serve’ basis and are not transferable between asset owners.

4.4.6 A significant disadvantage of the auctioned rights approach is the difficulty in setting a reserve price for the rights. The reserve price would be set at the cost of additional instantaneous reserve required to cover the risk represented by the rights. However, the future market prices of any additional instantaneous reserve required is unknown at the time rights are auctioned.

4.4.7 There would be some limitations on the transfer of rights between asset owners. Demand for short-term rights may be low as asset owners would want to acquire rights for the full life of their plant. A right in one geographical location may not be transferable to another, depending on security implications.

4.4.8 Auctioned rights and dispensations would have a very similar effect while the quantity of generation without fault ride through capability remained below the maximum limit. The limit may never be reached if asset owners chose to avoid the allocation of instantaneous reserve costs by installing plant compliant with the proposed fault ride through standards.

Question 4	Do you have any suggested market-based options that would be easier to implement than option A?

4.4.9 The Authority does not prefer option A because it has a much higher implementation cost than the proposal, and its medium term benefits are uncertain. The proposal has a lower level of complexity and does not preclude a move to other arrangements in the future.

Question 5	Do you agree that the proposal does not preclude a move to market-based arrangements in the future?

Option B – Combined standard for North and South Islands

4.4.10 Option B is a simplified variation of the proposal. It combines the North and South Island fault ride through envelopes described in the proposal to create a single composite standard to be applied across the whole country.

4.4.11 Of the two envelopes included in the proposal, the North Island envelope has the more onerous under-voltage performance requirement and the South Island the more onerous over-voltage requirement. A composite standard would combine these two sets of requirements to form a single combined standard applicable to the whole country.

4.4.12 Option B meets the objective of the Authority's proposal, but the advantages of a simplified standard would be potentially offset by an increase in compliance costs. Fault ride through standards are commonly based around regions in the larger European and North American a.c. power systems. A regional approach provides greater flexibility to target future updates to the standards as the mix of connected generation and the performance of protection systems change over time.

4.4.13 By comparison, New Zealand's power grid is much smaller, but the inherently different dynamic voltage characteristics of its North and South Island a.c. systems (being isolated by the HVDC link) support a regional approach. The difference between the characteristics of the North and South Islands may become more distinct over time and a regional approach allows greater flexibility to update the standard, should the need arise in the future.

4.4.14 The Authority does not prefer option B because:

(a) it has higher compliance costs that the proposed amendment

(b) it has less flexibility for future updates.

Option C – Standard used in another jurisdiction

4.4.15 This option would use a fault ride through standard developed by a jurisdiction which has already integrated large quantities of wind generation that could be considered to be generic or representative industry standard. It could be assumed that leading wind turbine manufacturers would have developed a level of compliance with the standards already in use in larger power grids.

4.4.16 There are many examples of existing fault ride through standards that could be adopted by New Zealand. A number of European countries including the Netherlands, Germany, Portugal, Spain, Germany, and Denmark have significantly higher wind energy penetration levels than New Zealand and over the past 10 years grid authorities in these countries have developed their own fault ride through standards.

4.4.17 The system operator surveyed the fault ride through standards used in the grid codes of 15 grid owners or countries in a literature review it completed. The characteristics of the sample of ride through envelopes investigated follow a consistent general pattern. However, the variation in the detailed prescription of these standards indicates that jurisdictions have tailored their standards to suit the individual conditions of their grids. Had such a standard existed, a number of leading manufacturers would have already designed and tested their plant to meet the standard.

4.4.18 As there is no one standard that could be considered to be a representative generic industry standard, the Authority does not prefer option C because it does not offer any cost advantages.

4.5 The proposed Code amendment complies with section 32(1) of the Act

4.5.1 Table 5 (below) demonstrates how the proposal complies with section 32(1) of the Act.

Table 5: How proposal complies with section 32(1) of the Act

Requirement	Comment
The proposed amendment is consistent with the Authority's objective under section 15 of the Act, which is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.	The proposed amendment contributes to the reliable supply of electricity to consumers and improves the efficient operation of the electricity industry.
The proposed amendment is necessary or desirable to promote any or all of the following:	

(a) competition in the electricity industry;	The proposed amendment will not materially affect competition in the electricity industry.
(b) the reliable supply of electricity to consumers;	The proposed amendment contributes to the reliable supply of electricity to consumers by reducing the risk of consumer loss of supply as a result of generation disconnecting from the grid during grid faults.
(c) the efficient operation of the electricity industry;	The proposed amendment improves the efficient operation of the electricity industry by reducing the quantity of under frequency reserve required to protect against loss of injection from disconnected generation.
(d) the performance by the Authority of its functions;	The proposed amendment will not materially affect the performance by the Authority of its functions.
(e) any other matter specifically referred to in this Act as a matter for inclusion in the Code.	The proposed amendment will not materially affect any other matter specifically referred to in the Act for inclusion in the Code.

Question 6 Do you agree the Authority's proposed amendment complies with section 32(1) of the Act?

4.6 The Authority has had regard to the Code amendment principles

4.6.1 When considering amendments to the Code, the Authority is required by its Consultation Charter[13] to have regard to the following Code amendment principles, to the extent that the Authority considers that they are applicable. Table 6 (below) describes the Authority's regard for the Code amendment principles in the preparation of the proposal.

13 The consultation charter is one of the Authority's foundation document and is available at:: http://www.ea.govt.nz/about-us/documents-publications/foundation-documents/

Table 6: Regard for Code amendment principles

Principle	Comment
1. Lawful	The proposed amendment is lawful, and is consistent with the statutory objective (see section 4.4.17) and with the empowering provisions of the Act.
2. Provides clearly identified efficiency gains or addresses market or regulatory failure	The efficiency gains are set out in the evaluation of the costs and benefits (section 4.3). Efficiency gains are derived from a reduction in the quantity of under frequency reserve required to protect against failure of generating plant to ride through transmission faults. The proposed amendment does not materially affect market behaviour and is not intended to address any market failure.
3. Net benefits are quantified	The extent to which the Authority has been able to estimate the efficiency gains is set out in the evaluation of the costs and benefits (section 4.3). There are positive net benefits across a range of scenarios and therefore the Authority's other Code amendment principles are not relevant.

Glossary of abbreviations and terms

Act	Electricity Industry Act 2010
AOPO	Asset owner performance obligation
AUFLS	Automatic under frequency load shedding
Authority	Electricity Authority
Cascade failure	Partial or complete system failure resulting from sympathetic tripping of generating and transmission assets
CE	Contingent event
Code	Electricity Industry Participation Code 2010
ECE	Extended contingent event
Grid reliability standards	The standards for reliability of the grid developed in accordance with clauses 12.55 to 12.58, 12.61 and 12.62 of the Code
FIR	Fast instantaneous reserve
Fault ride through	The ability of non-faulted assets to remain stable and connected during system faults
HVDC	High voltage direct current link
HVDC bipole trip	Rapid decrease in power transfer on both HVDC poles
IR	Instantaneous reserve, an ancillary service comprising of interruptible load, or partly loaded spinning reserve, or tail water depressed reserve
NPV	Net present value
Non-faulted assets	Assets not disconnected directly by protection systems as a result of a fault
p.u.	The per unit system (in the context of this paper, the ratio of grid line to line voltage to its base value of 220 kV or 110 kV, as applicable)
Ratio-based standard	An over voltage fault ride through standard that defines ride through capability in terms of the ratio of voltage during the fault to the voltage immediately before the fault
RMT	Reserve management tool

SIR	Sustained instantaneous reserve
System operator security policy	The general policies the system operator intends to use to meet its principal performance obligations (refer to chapter 1 of the Policy Statement)
Synchronous generating unit	Output frequency of a synchronous unit is exactly determined by rotor speed, as opposed to an non-synchronous unit where output frequency is slightly lower than the frequency determined by rotor speed
WGIP	Wind generation investigation project

Appendix A **Proposed Code amendment**

This Appendix presents the amendments proposed to the Code.

1. Insert in clause 1.1, in its appropriate alphabetical order, the following definition:

reactive current means the component of electrical current on a **line** 90 degrees out of phase with the **voltage** on the **line**.

2. Add the following clauses to subpart 2 of part 8 of the Code.

8.25A Fault ride through

(1) Each **generator** must ensure that each of its **assets**, when **connected** to the **grid** at 110 kV or 220 kV, is capable of remaining stable and **connected** when the **grid line** to **line** voltage is within the no-trip zone shaded and marked "No-trip zone" in Figure 8.1 (for an **asset** in the North Island) or Figure 8.2 (for an **asset** in the South Island) for the period of 6 seconds immediately following the commencement of a zero impedance three-phase short circuit fault, or an unbalanced short circuit fault, on any part of the **grid** in the **island** in which the **asset** is **connected**.

(2) Each **generator** must ensure that each of its **assets**, when **connected** to the **grid** is capable of, remaining stable and **connected** when the **line** to **line** voltage at Haywards 220 kV bus (for an **asset** in the North Island) or Benmore 220 kV bus (for an **asset** in the South Island) is within the no-trip zone shaded and marked "No-trip zone" in Figure 8.3 for the period of 1 second immediately following the commencement of a trip of the **HVDC link**.

(3) Whether a **generator** is complying with subclause (2) must be determined using power system analysis that uses–

(a) study cases provided by the relevant **grid owner**; and

(b) relevant system assumptions provided by the **system operator**.

(4) A **generator** is not required to comply with subclause (1) in respect of an **asset** in the event of a fault of a type described in subclause (1), if the **asset** becomes isolated from the **grid** as a result of the fault.

(5) A **generating unit** need not comply with subclause (1) to the extent that it is complying with a **special protection scheme** approved by the **system operator**.

(6) The absolute **grid** voltage (per unit) shown on the Y axis of Figure 8.1 and Figure 8.2 is the ratio of **grid line** to **line** voltage on a **line** to the nominal operating voltage of the **line** (that is, 110 kV or 220 kV).

Figure 8.1: North Island no-trip zone during 110 kV or 220 kV faults

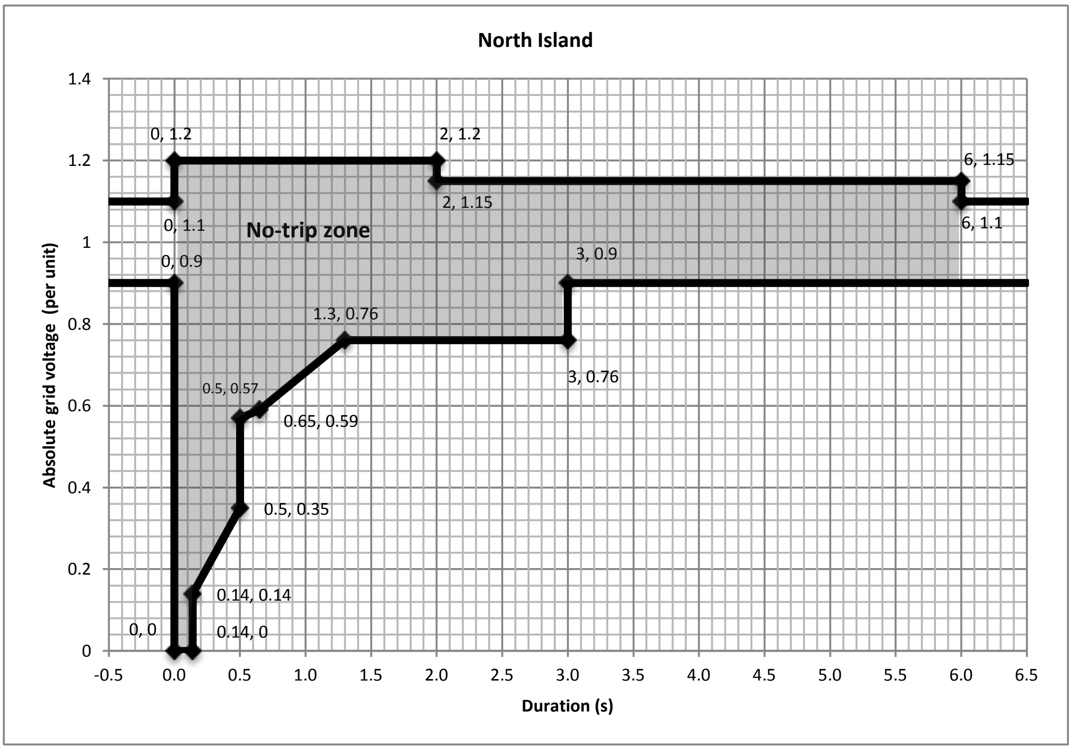


Figure 8.2: South Island no-trip zone during110 kV or 220 kV faults

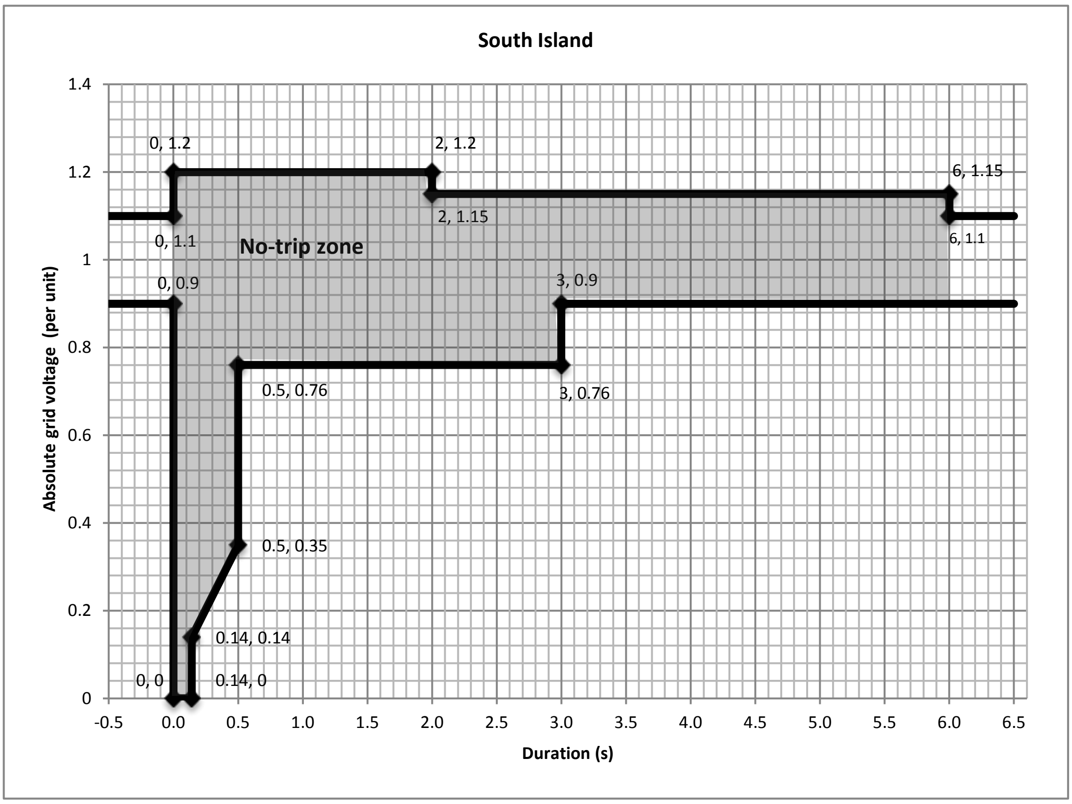
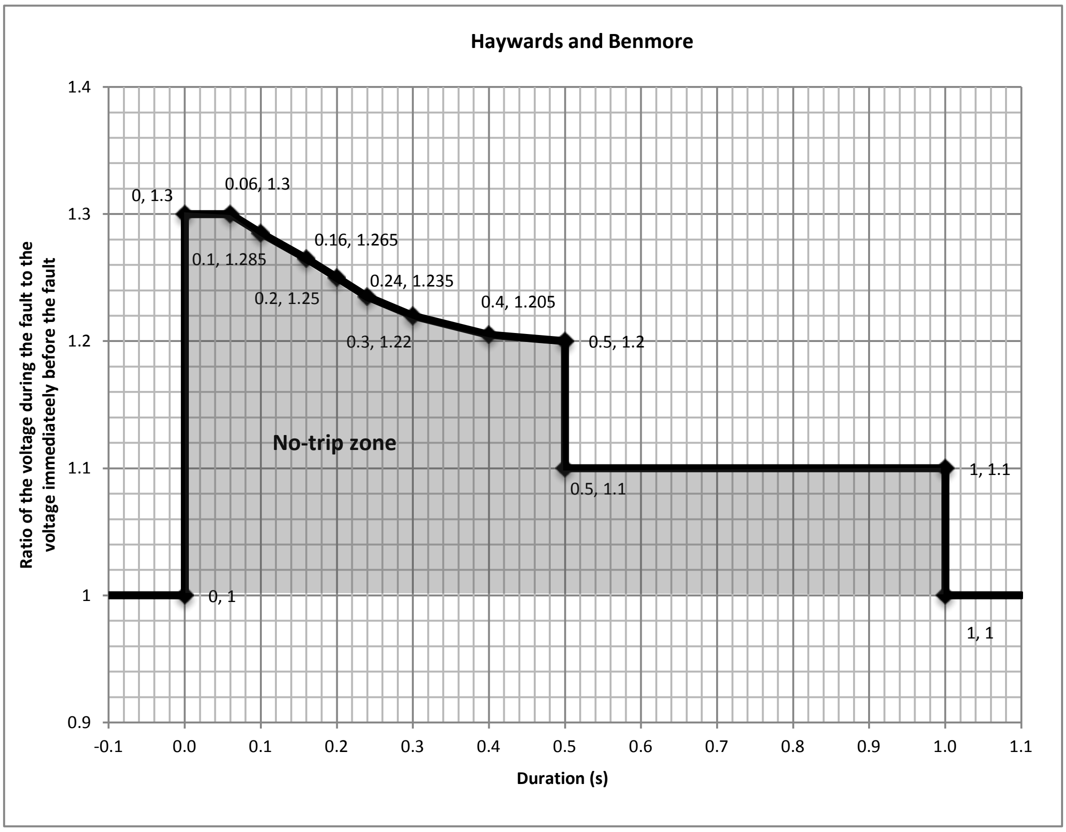


Figure 8.3: Haywards and Benmore no-trip zone during permanent loss of the HVDC link



8.25B Reactive current and active power output

(1) Each **generator** must ensure that each of its **generating units** generates at least the maximum **reactive current** specified in the **generator asset capability statement** for the period of 6 seconds immediately following the commencement of a fault on the **grid** described in clause 8.25A(1).

(2) Each **generator** must ensure that each of its **generating units** provides **active power** output relative to pre-fault **active power** output at least in proportion to the **grid voltage** at the **grid injection point** for the period of 6 seconds immediately following the clearance of a fault on the **grid** of a type described in clause 8.25A(1).

(3) Subclause (2) does not apply to a **wind generating station** if there has been a reduction in the intermittent wind power source during the 6 seconds following the commencement of the fault.

8.25C Use of additional equipment

A **generator** may comply with clause 8.25A in relation to a **generating station** by—

(a) ensuring that the performance of **generating units** that comprise the **generating station** comply; or

(b) installing additional equipment within the **generating station**; or

(c) a combination of the methods described in paragraphs (a) and (b).

8.25D Application

(1) Clauses 8.25A and 8.25B do not apply—

(a) to a **wind generating station** when it operates at less than 5% of rated **MW**:

(b) to any **asset** at an **excluded generating station**.

3. Amend clause 8.21 of the Code as follows:

Excluded generating stations

8.21 Excluded generating stations

(1) For the purposes of clauses 8.17, 8.19, 8.25D and the provisions in **Technical Code** of Schedule 8.3 relating to the obligations of **asset owners** in respect of frequency……..

4. Amend clause 8.38 of the Code as follows:

8.38 Authority may require excluded generating stations to comply with certain clauses

(1) Despite clauses 8.17 and 8.25D, the **system operator** may, at any time, apply to the **Authority** for the **Authority** to issue a directive that an **excluded generating station asset** must comply with clauses 8.17, 8.19, 8.25A and 8.25B..

Question 7	Do you have any comments on the drafting of the proposed amendment?

Appendix B Format for submissions

Submitter	

Question		Comment
Question 1	Do you agree the issues the Authority has identified are worthy of attention?	
Question 2	Do you agree with the objectives of the proposed amendment? If not, why not?	
Question 3	Do you agree the benefits of the proposed amendment outweigh its costs?	
Question 4	Do you have any suggested market-based options that would be easier to implement than option A?	
Question 5	Do you agree that the proposal does not preclude a move to market-based arrangements in the future?	
Question 6	Do you agree the Authority's proposed amendment complies with section 32(1) of the Act?	
Question 7	Do you have any comments on the drafting of the proposed amendment?	
Clause	8.20A	
Clause	8.20B	
Clause	8.20C	
Clause	8.20D	
Clause	8.21	
Clause	8.38	

Appendix C **Operating and planned wind generation**

Operating	Commissioned	Operator	Number of turbines	Installed capacity MW	Annual average Generation	Capacity factor
NORTH ISLAND						
Hau Nui	1997	Genesis Energy	15	8.65	22	29%
Mill Creek	Jun-14	Meridian Energy		59.8		
Project West Wind	2009	Meridian Energy	62	142.6	550	44%
Tararua	1999-2007	Trustpower	134	161	650	46%
Te Apiti	2004	Meridian Energy	55	91	258	32%
Te Rere Hau	2006-11	NZ Windfarms	97	48.5	160	38%
Te Uku	2011	WEL Networks / Meridian Energy	28	64.4	225	40%
SOUTH ISLAND						
Flat Hill	2015			6.8		
Horseshoe Bend[11]	2009	Pioneer Generation	3	2.25	8	41%
Lulworth	Jan-11	Energy³	4	1	3.2	37%
Mahinerangi	Mar-11	Trustpower	12	36	112	36%
Mt Stuart[12]	Dec-11	Pioneer Generation	9	7.65	25.6	38%
Weld Cone[13][14]	2010	Energy³	3	0.75	3	46%
White Hill	2007	Meridian Energy	29	58	200	39%
As at January 2015		Weighted capacity factor=		41%		
		Annual Generation=		2217	GWh	
		Total Installed capacity =		688	MW	
		North Island Installed capacity =		576	MW	
		North Island Installed capacity =		112	MW	

Planned	Consented	Operator		Installed capacity
Awakino		Ventus		41.6
Awhitu	Y	Genesis Energy		25
Chatham Island		CBD Energy		0.4
Central Wind	Y	Meridian Energy		130
Hauauru ma raki		Contact Energy		540
Hawke's Bay	Y	Hawkes Bay Wind Farm Ltd		225
Kaiwera Downs	Y	TrustPower		240
Long Gully	Y	Mighty River Power		12.5
Lulworth		Energy 3		1
Mahinerangi		TrustPower		200
Mill Creek		Meridian Energy		71
Mount Cass	Y	MainPower		69
Mount Stuart		NZ Windfarms		6
Project Gumfields		Meridian Energy		99
Project Hayes		Meridian Energy		630
Project Central Wind		Meridian Energy		130
Puketiro		RES NZ		150
Rototuna		Meridian Energy		500
Slopedown		Wind Prospect CWP (NZ) Ltd		150
Taharoa	Y	Taharoa C		100
Taumatatotora	Y	Ventus Energy		44
Titiokura	Y	Unison Networks and Roaring 40s		45
Turitea	Y	Mighty River Power		360
Waitahora	Y	Contact Energy		177
Waverley		Allco Wind Energy		135

Appendix D 2011 Consultation

This Appendix includes the consultation paper published in February 2011.

Consultation Paper

Generation Fault Ride Through

Prepared by the Electricity Authority
February 2011

908325-1

Executive summary

The Electricity Authority (Authority) has conducted a review of the asset owner performance obligations under the Electricity Industry Participation Code 2010 (Code) which require non-faulted generating assets to remain connected during transmission faults. As a result of this review, the Authority considers the performance obligations for generation fault ride through capability should be improved with the objective of maintaining the long term security of the grid.

The power system is designed and operated so that any credible event resulting in loss of generation will not produce an under-frequency event large enough to cause widespread customer loss of supply. A fault may cause a large scale voltage dip as low as zero volts at the point of the fault and nearby generation will experience a short term reduction in voltage which is dependent on the proximity to the fault.

Most traditional synchronous generating units are capable of operating in a stable manner through such a transient voltage disturbance that accompanies a transmission fault. Depending on the type of technology used, the capability of wind generation technologies to ride through faults and provide voltage support during voltage disturbances is inherently different to that of synchronous generating plant. In the absence of appropriate performance standards, the displacement of synchronous generation by increasing quantities of wind plant will have an impact on the security of the grid.

Many international utilities have introduced fault ride through standards to manage the impact of changes in the mix of generation connected to their grids. In response to the introduction of new standards, wind turbine manufacturers have made advances in the capability of certain classes of plant to ride through faults and support recovery of grid voltage after faults.

The Authority commissioned the System Operator to investigate the current and future dynamic voltage performance of the New Zealand power system and to develop recommended fault ride through envelopes to suit conditions in the North and South Island power systems. The Authority proposes to add fault ride through standards for all types of generating plant to the Code. The standards would require generators to ensure that their generating assets:

(a) remain transiently stable and connected to the power system without tripping while system voltage remains within a defined under and overvoltage envelope following a fault on the transmission system;

(b) maintain power output during and following a fault to avoid complete loss of power injection into the grid; and

(c) provide the maximum possible reactive current injection during a fault to minimise voltage dip and support recovery of system voltage following a fault.

Proposed changes to the Code are included in Appendix B.

Glossary of abbreviations and terms

Authority	Electricity Authority
Act	Electricity Industry Act 2010
Code	Electricity Industry Participation Code 2010

Contents

Tables

Figures

1. Introduction and purpose of this paper

1.1 Introduction

1.1.1 The Authority has reviewed the obligations in the Code for non-faulted generating assets to remain connected during transmission faults, to supply enough reactive power to reduce voltage dip, and to provide enough short-circuit current to allow protection relays to clear faults correctly. As a result of the review's findings and work carried out in conjunction with the System Operator, the Authority proposes that fault ride through standards for all generating plant be added to the Code. Separate standards in the form of ride through envelopes are proposed for the North and South Islands.

1.2 Purpose of this paper

1.2.1 The purpose of this paper is to consult with participants and persons that the Authority thinks are likely to be substantially affected by the proposed generation fault ride through standards.

1.2.2 The purpose of this Code change proposal is to specify fault ride through requirements for all generation connected to the New Zealand grid. The System Operator would be responsible for operating the power system within such requirements to ensure that it is able to meet its principle performance objectives.[1]

1.2.3 This paper is a regulatory statement in accordance with section 39 of the Electricity industry Act 2010 (Act). As such, it sets out a statement of the objectives of the proposed amendment, an evaluation of the costs and benefits of the proposed amendment and an evaluation of alternative means of achieving the objectives of the proposed amendment.

1.2.4 The Authority invites submissions on the proposals in this paper, including drafting comments on the proposed changes to the Code.

1.3 Submissions

The Authority's preference is to receive submissions in electronic format (Microsoft Word). It is not necessary to send hard copies of submissions to the Authority, unless it is not possible to do so electronically. Submissions in electronic form should be emailed to submissions@ea.govt.nz with Consultation Paper—Generation Fault Ride Through in the subject line.

If submitters do not wish to send their submission electronically, they should post one hard copy of their submission to either of the addresses provided below.

[1] Clause 7.2 (1) (a) of the Electricity Industry Participation Code 2010.

Submissions

Electricity Authority

PO Box 10041

Wellington 6143

Submissions

Electricity Authority

Level 7, ASB Bank Tower

2 Hunter Street

Wellington

Tel: 0-4-460 8860

Fax: 0-4-460 8879

1.3.1 Submissions should be received by 5pm on 11 March 2011. Please note that late submissions are unlikely to be considered.

1.3.2 The Authority will acknowledge receipt of all submissions electronically. Please contact the Submissions' Administrator if you do not receive electronic acknowledgement of your submission within two business days.

1.3.3 If possible, submissions should be provided in the format shown in Appendix A. Your submission is likely to be made available to the general public on the Authority's website. Submitters should indicate any documents attached, in support of the submission, in a covering letter and clearly indicate any information that is provided to the Authority on a confidential basis. However, all information provided to the Authority is subject to the Official Information Act 1982.

2. Background

2.1 Overview

2.1.1 The New Zealand power system regularly experiences disturbances as a result of single phase and three phase a.c. transmission faults, generating unit faults and loss of injection from the HVDC link. A fault may cause a frequency disturbance and a large system voltage dip at the location of the fault. Generation at remote locations will experience a reduction in voltage which is dependent on proximity to the fault.

2.1.2 Sympathetic tripping of non-faulted assets may lead to voltage or frequency instability and, in extreme cases, cascade failure. It is important that non-faulted generating and transmission assets remain connected and ride through periods of voltage and frequency disturbances during and following a fault.

2.1.3 The Code specifies dynamic frequency performance obligations for generators to ensure that their assets remain connected to the grid during frequency disturbances (clause 8.19 of the Code). The obligations are expressed in the form of under and over-frequency performance envelopes for the North and South Island.

2.1.4 There are no similar dynamic performance envelopes specified for asset owners to ensure their assets remain transiently stable and connected to the grid during voltage disturbances. However, the Code includes a limited set of performance obligations for asset owners to ensure that non-faulted assets remain connected during disturbances, to supply enough reactive power to reduce voltage dip, and to provide enough short-circuit current to allow protection relays to clear faults correctly.

2.1.5 The obligations in the Code include:

(a) a requirement for grid connected generators to be operable over a range of grid voltages ($\pm$ 10% for 220 kV and 110 kV, and $\pm$ 5% for 66 kV and 50 kV, clause 8.22(2));

(b) a requirement that protection systems operate selectively to disconnect the minimum amount of plant and preserve power system stability during faults (clause 4(4)(a)(ii) of technical code A of schedule 8.3);

(c) a requirement that generating units' voltage control systems be designed and have settings to support the System Operator in meeting the Principal Performance Obligations e.g. to avoid cascade failure during voltage excursions (clause 5(1)(a)(i) of technical code A of schedule 8.3); and

(d) a requirement for grid connected generators to provide reactive power capability over a range of grid voltages to support the System Operator in maintaining grid voltage within acceptable limits and secondly, to support the System Operator in maintaining voltage stability on the grid (clause 8.23).

2.1.6 The general obligations in the Code have ensured satisfactory system performance while the generation mix connected to the grid has remained predominantly synchronous. Most traditional synchronous generating units are capable of operating through the transient voltage dip that accompanies a system fault. A fault on a generating unit or its connections to the grid will generally not cause the loss of any other synchronous generating unit outside the faulted zone. The transmission system is designed and operated on this basis.

2.1.7 The mix of generation is changing with 500 MW of wind generation now connected to the grid producing 4% of New Zealand's electricity generation. With the introduction of new forms of generation there is a need to review and update the voltage performance obligations in the Code.

2.2 Impact of wind generation

2.2.1 Wind generation technologies have different capabilities to ride through faults and provide voltage support during voltage disturbances to synchronous generating plant. The effect of wind generation on the dynamic voltage performance of the New Zealand power system was studied in detail in an investigation carried out by Transpower in 2008 as part of the Electricity Commission's Wind Generation Investigation Project (WGIP).

2.2.2 The WGIP looked at the impact of the displacement of synchronous generating units on the grid by the different types of wind generation technology. The investigation concluded that[2]:

> "Large scale wind generation will affect power system dynamic voltage support in two ways:
>
> - The displacement of other plant on the grid by wind generation will affect the power system's ability to provide reactive power support during and following faults on the power system. The effects can be positive or negative depending on the location of the displaced generation and the wind generation, and the type of wind generation technology employed.
> - The dynamic behaviour of different wind generation technologies during short circuit fault conditions is governed by the intrinsic characteristics of the generators and their control systems."
>
> "Wind generation has a more limited capability to provide voltage support during faults than does other generating plant, such as synchronous generating units. The displacement of plant, such as synchronous generating units, by wind

[2] Wind Generation Investigation Project: Investigation 9 – Effect of wind generation on reactive power contribution and dynamic voltage responses available at: http://www.ea.govt.nz/our-work/programmes/pso-cq/wgip/

generation will lower short circuit levels and lower voltage dip performance. Short circuit levels and voltage dip performance will be most affected in areas where local generation is displaced by remote wind generation. In areas where local generation is displaced by local wind generation the effects on short circuit levels and voltage dip performance are lessened. The installation of wind generation in areas where there is little other generation can improve short circuit levels and voltage dip performance if DFIG *[doubly-fed induction generator]* or FSFC *[full scale frequency converter]* technology is employed".

2.2.3 Further to these conclusions, the WGIP recommended that dynamic fault ride through requirements for grid connected generators be incorporated into the Code. Such requirements would improve the System Operator's ability to manage its obligation to avoid cascade failure during voltage disturbances. In addition, more specific dynamic fault ride through requirements would provide greater certainty for developers in specifying performance requirements for new generating plant.

2.2.4 These recommendations were supported by submissions received on the consultation paper on Wind Integration Options.

2.3 Fault ride through literature review

2.3.1 In response to the WGIP recommendation, the former Electricity Commission engaged the System Operator to investigate fault ride through criteria used in other jurisdictions that could be applied to the New Zealand power system. The investigation included a review of the New Zealand grid planning criteria, New Zealand power system protection requirements, previous ride through studies, and the ability of generators to meet fault ride through standards.

2.3.2 The System Operator's literature review report can be downloaded from:

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

2.3.4 The System Operator reviewed the grid codes of 15 grid operators internationally. It was found that 14 codes included a low voltage ride through capability requirement and additionally, 8 included a high voltage ride through requirement.

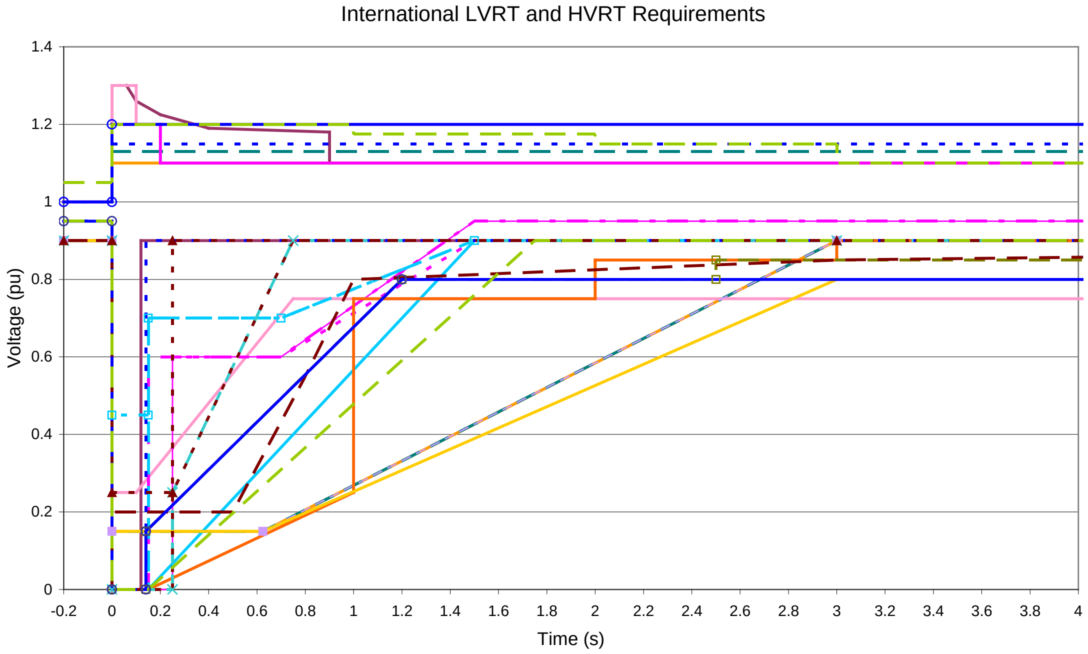
2.3.5 Some of the codes required active power to be restored within a minimum gradient and/or to a defined output level within a specific time to minimise any under-frequency effects resulting from loss of power injection during faults. In addition, other codes specified reactive current requirements during faults to minimise voltage and support post fault voltage recovery.

2.3.6 Figure 1 below shows the low and high voltage ride through envelopes specified in the 15 grid codes reviewed. It is clear that while the fault ride through envelopes of these codes have similarities, there is no close correlation between the envelopes. There is no single common international standard in use and jurisdictions have tailored requirements to suit the particular conditions that prevail in the respective power systems.

2.3.7 Of note are the more stringent grid codes used in Australia (AEMC), Germany (E.ON), Norway (Energinet/Nordel), Denmark (Energinet/Nordel), Sweden (SvK), Hydro-Quebec and Western USA (WECC) which require generation to remain connected during voltage dips down to 0%. Other codes commonly stipulate minimum voltages in the range of 15-25%.

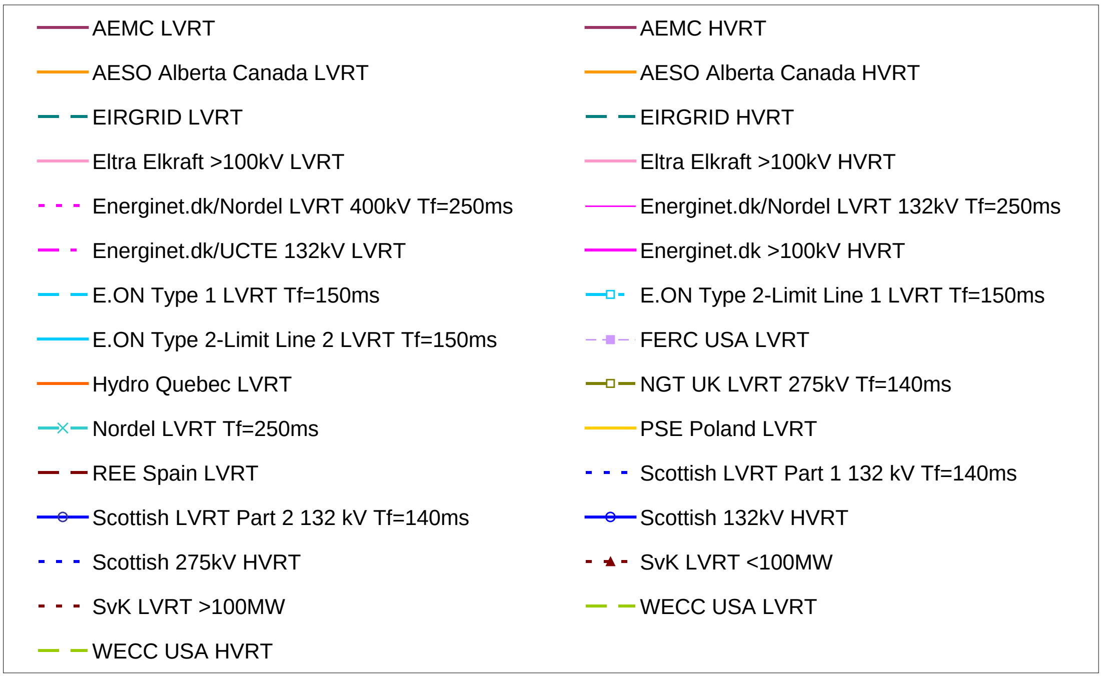
2.3.8 The review found that wind generators connected via a full scale frequency converter have a fault ride through capability that generally complied with the international grid codes investigated. Doubly-fed induction generators and fixed speed induction have a lesser ride through capability and would not comply with some grid codes.

Figure 1: Under and overvoltage requirements for other grid codes[3]



(refer to legend overleaf)

3 Source: Generator Fault Ride Through Investigation Report, System Operator



2.4 Dynamic voltage performance of the NZ power system

2.4.1 In a second stage of work, the Electricity Commission asked the System Operator to complete a full investigation into the current and future dynamic voltage performance of the New Zealand power system. The investigation used the protection setting data and the planning criteria researched in the literature review.

2.4.2 The detailed results of the System Operator's investigation can be downloaded from:

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

2.4.3 The System Operator's investigation determined that the transient performance of the power system is determined largely by three factors:

(a) the fault type (location, voltage, single or three phase);

(b) the clearance time for protection to isolate the fault; and

(c) the characteristic of the load on the system at the time of the fault.

2.4.4 Of these factors, the nature of the load has the greatest impact on system performance under faulted conditions. The reactive power absorbed by motor load increases during a fault and determines the characteristic of the voltage recovery after the fault is cleared. The System Operator used a composite load model at each GXP made up of a percentage of static (non-motor load) and three sizes of induction motor load.

Modelling assumptions

2.4.5 The following modelling assumptions were used by the System Operator in the studies:

(a) the load model was based on current practice used by the Grid Owner to determine current and future reactive power requirements for the grid;

(b) summer peak load was used as the worst case to determine the transient under-voltage envelope;

(c) light load with the loss of an HVDC pole at Benmore or Haywards was used to determine the transient over-voltage envelope;

(d) three phase zero impedance faults resulting in the loss of a single element were applied in all studies;

(e) fault contingencies considered were:

(i) loss of a single transmission circuit;

(ii) loss of a single generating unit;

(iii) loss of an HVDC pole;

(iv) loss of a single dynamic reactive plant (static var compensator); and

(f) committed system upgrades were modelled through to 2015.

Study methodology

2.4.6 The System Operator carried out dynamic voltage performance studies using a methodology which involved:

(a) developing load flow cases based on the set of assumptions outlined in paragraph 2.4.5 above;

(b) converting the load to static and dynamic load compositions using the approach described in paragraph 2.4.4);

(c) applying the appropriate critical contingencies and fault type;

(d) clearing the fault at the design operating time; and

(e) running dynamic simulations for five seconds or until the system reaches a steady state condition.

2.4.7 The Grid Owner’s HVDC over and under-voltage envelope previously developed for the pole 3 project was compared in the formulation of the final island wide fault ride through envelopes.

Q1.	Do you agree with the System Operator's modelling assumptions and study methodology?

Under-voltage ride through envelope

2.4.8 In order to determine the overall transient under-voltage system performance the System Operator grouped results by bus voltage and contingency. The contingencies that in most cases have the most onerous and widespread effect were found to be the major 220 kV circuits or generators in the North and major 220 kV circuits in the South Islands.

2.4.9 The transient under-voltage system performance in the North and South Islands were found to be sufficiently different to warrant the use of separate envelopes in each island.

2.4.10 In some areas of the South Island it was found that certain 110 kV and 66 kV contingencies had a more onerous local effect than the major 220 kV contingencies. However, the impedance of supply and interconnecting transformers limits the extent of severe transient voltage dip from these contingencies across the transmission network. Due to their more localised effect, these contingencies were not included as part of the criteria to determine the overall fault ride through envelopes for the North and South Islands.

2.4.11 The System Operator averaged the 10 worst bus results on an island basis, after removing localised bus issues, to produce a single under-voltage envelope for each island. The results were averaged to counterbalance the conservative nature of the fault and load modelling assumptions.

2.4.12 The resulting under-voltage envelopes were overlaid on the Grid Owner's HVDC under-voltage envelope and composite envelope produced to account for both a.c. and HVDC contingencies.

2.4.13 Finally, a safety factor of 5% was added to the composite envelopes to allow for a margin of error in the assumptions made in the composite load model for the quantity of motor load tripped during fault contingencies[4].

Over-voltage ride though envelope

2.4.14 Currently, the worst case condition for transient over-voltage in either island is the loss of pole 2 of the HVDC link at either Benmore or Haywards. This condition arises due to the quantity of reactive power rejected by the link when pole 2 trips.

4 Voltage dip will increase if less motor load trips than is modelled.

2.4.15 When Pole 3, which was not considered in the analysis, is commissioned in 2012, pole 2 and pole 3 will offer some voltage modulation for the loss of the other pole. A review of the transient over-voltage envelope may be warranted after 2012 if generators experience technical difficulty in meeting the specified criteria.

2.4.16 The System Operator added a safety factor of 5% to the over-voltage envelope to allow for a margin of error in the assumptions made in the composite load model for the quantity of motor load tripped during fault contingencies[5].

2.4.17 The Grid Owner's HVDC over-voltage envelope is based on a full bipole rejection of 1400 MW, the future capacity of the link, rather than the loss of a single pole. The initial rise in voltage exceeds 1.4 p.u. and is greater than any of the international grid codes studied and greater than the capability of the typical wind turbines investigated.

2.4.18 On this basis, it was decided to use only the loss of pole 2 as the critical contingency for the North and South Island over-voltage envelopes.

2.4.19 The final under and over-voltage envelopes recommended by the System Operator are shown in tabulated form in Table 1 and Table 2, and in graphical form in Figure 2 and Figure 3.

Table 1: Proposed North Island fault ride through envelope

Over-voltage		Under-voltage	
Time (s)	**Voltage pu**	**Time (s)**	**Voltage pu**
-0.1	1.09	-0.2	0.9
0	1.09	0	0.9
0	1.21	0	0
0.3	1.16	0.14	0
0.5	1.16	0.14	0.14
0.5	1.1	0.5	0.35
2.25	1.1	0.5	0.57
2.9	1.1	0.65	0.59
3.9	1.1	1.3	0.76
4.9	1.1	3	0.76
5	1.1	3	0.9

[5] Over-voltage will increase if more motor load trips than is modelled.

Table 2: Proposed South Island fault ride through envelope

Over-voltage		Under-voltage	
Time (s)	**Voltage pu**	**Time (s)**	**Voltage pu**
-0.1	1.08	-0.2	0.9
0	1.08	0	0.9
0	1.23	0	0
0.38	1.18	0.14	0
0.4	1.1	0.14	0.14
2.12	1.1	0.5	0.35
3.9	1.1	0.5	0.76
4.9	1.1	3	0.76
5	1.1	3	0.9

Figure 2: Proposed North Island fault ride through envelope[6]

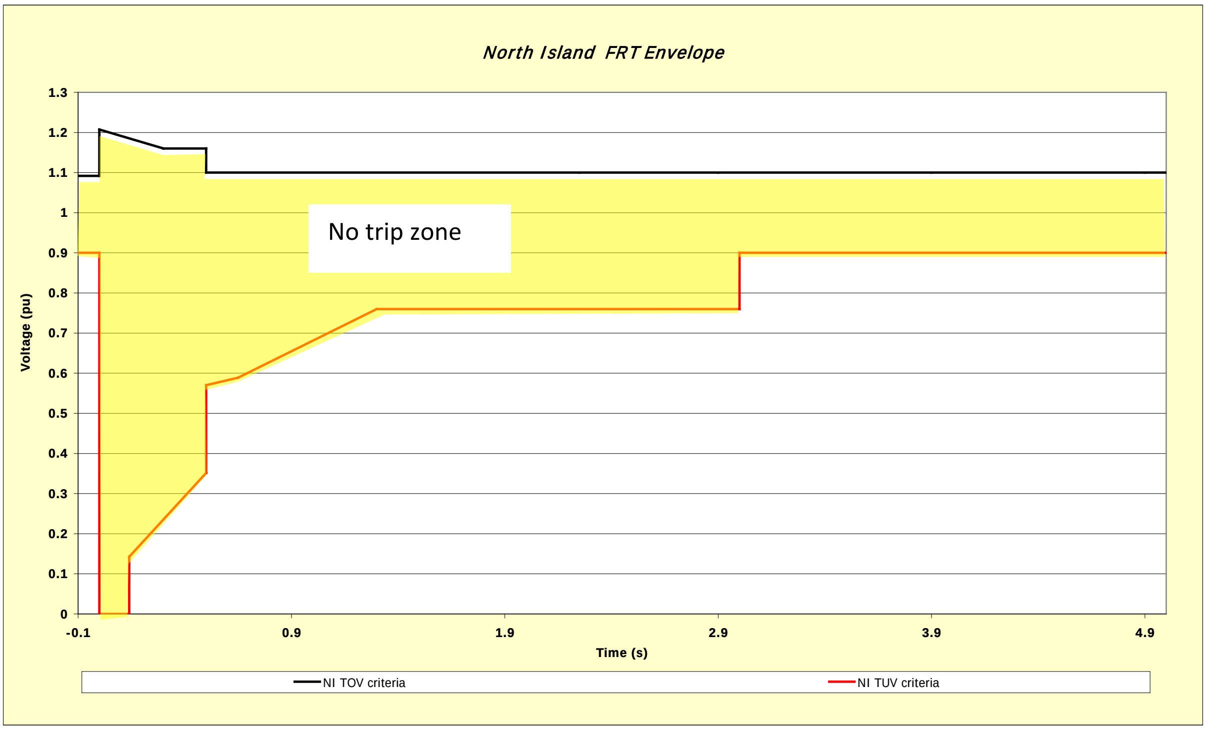
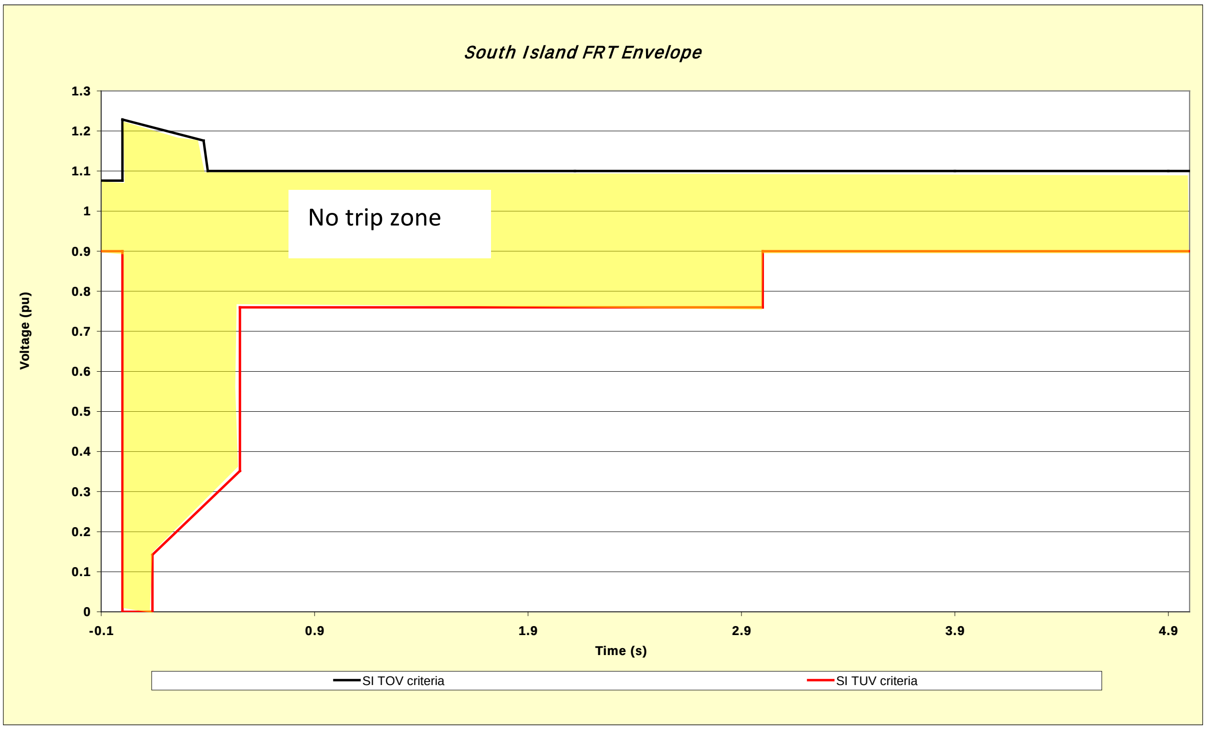


Figure 3: Proposed South Island fault ride through envelope[6]



6 Source: Generator Fault Ride Through Investigation Report – System Operator

3. Issues and options

3.1.1 A loss of injection into the grid by generators or the HVDC can cause an under-frequency event which by its nature extends across the entire a.c system in the North or South Island. Frequency effects are widespread across the grid and can potentially cause system collapse. Historically, a number of under-frequency controls have been employed to manage loss of injection of generation into the grid.

3.1.2 The under-frequency controls used include a mix of market procured services and mandated under-frequency performance obligations placed on generating plant. The controls are configured for the dynamic under-frequency performance of the power system which is assessed against credible contingency risks in each market trading period.

3.1.3 By comparison, the measures used to manage under-voltage events are less well defined. Clause 8.22(2) of the Code requires generating units to remain connected only when system voltage is inside the normal range which must be maintained by the grid owner (± 10% for 220 kV and 110 kV).

3.1.4 The WGIP recognised that the mix of generation is changing with the introduction of new forms of generation which have varying under-voltage ride through capability. The WGIP identified a need to review the voltage performance obligations in the Code and recommended that the Code be updated to incorporate dynamic fault ride through requirements for grid connected generators. These recommendations were supported by submissions received from participants on the consultation paper on Wind Integration Options.

3.1.5 In addition, the WGIP identified the importance of maintaining adequate short circuit levels on the power system to ensure that enough short circuit reactive power is supplied during faults to reduce the magnitude of voltage dip and supply enough short circuit current during faults to allow protection relays to operate correctly. The displacement of synchronous generation by certain types of wind generation technology has the potential to cause more severe voltage dips and prolong system voltage recovery times.

3.1.6 Investigations carried out by the System Operator indicate that inclusion of dynamic fault ride through standards in the Code would not be out of step with the requirements in grid codes of many international jurisdictions. The System Operator found that newer wind generation technology is capable of riding through major faults that suppress voltage over large parts of the grid in New Zealand, provided that appropriate performance requirements are included in the specification of the plant.

3.1.7 The Authority proposes changes to the Code to establish specific fault ride through standards for all generating plant connected to the grid. Options considered for the standards include the following:

(a) the proposal developed by the System Operator involving a separate standard for the North and South Islands;

(b) the status quo, relying on the existing asset owner performance obligations in the Code for generator protection settings, voltage control systems and reactive power capability;

(c) a standard for both the North and South Islands based on the combined requirements of the System Operator's North and South Island proposals; and

(d) a standard that matches the requirements already developed in other international grid codes.

4. Proposal and analysis

4.1 The Authority's proposal

4.1.1 The Authority proposes to add fault ride through standards for generating plant to the Code based on option (a) as set out in paragraph 3.1.7 The standards would require generators to ensure that their generating assets:

(a) remain transiently stable and connected to the power system without tripping while system voltage remains within a defined under and overvoltage envelope following a fault on the transmission system;

(b) maintain mechanical power output during and following a fault to avoid loss of power injection into the grid; and

(c) provide the maximum possible reactive current injection during a fault to minimise voltage dip and support recovery of system voltage following a fault.

In the case of wind generating stations, the requirements should apply only in circumstances when generating units are able to operate in a stable mode, i.e. when wind speeds are within a margin of the cut-in and cut-out speeds of the units.

4.1.2 Separate fault ride through envelopes are proposed for the North and South Island based on the proposal provided to the Authority by the System Operator. These are defined by the co-ordinates given in Table 1 and Table 2 and shown graphically in Figure 2 and Figure 3. The Authority proposes minor adjustments to the envelopes derived by the System Operator to align pre-fault voltages with the maximum and minimum grid operating voltages for 110 kV and 220 kV specified in clause 8.22 (2) of the Code (1.1 pu and 0.9 pu respectively).

4.1.3 The envelopes produced by the System Operator are supported by detailed studies of the transient voltage performance of the grid under a range of credible system conditions and fault scenarios. The envelopes are a derived overall transient voltage system performance characteristic for each of the North and South Islands.

4.1.4 The fault ride through requirements would apply to three-phase and any unbalanced short circuits at grid voltages of 220 kV and 110 kV. Faults at these system voltages cause voltage to be suppressed over extended areas of the grid and affect significant numbers of generating units across the power system. Faults on lower sub-transmission grid voltages may have more onerous effects on locally connected generating plant but the quantity of generating plant at risk is very small compared to that for faults at 220 kV or 110 kV.

4.1.5 Consistent with the deminimus that applies to obligations in the Code for generators to support frequency in the normal band and support frequency in under frequency events, it is proposed that the fault ride through standard apply to generating stations that export greater than 30 MW to a local network or the grid. Tripping of a group of small stations within a region as a result of a grid fault would have limited effect on the dynamic performance of the grid.

Q2.	**Should the fault ride through standard apply to generating stations smaller than 30 MW?**

4.1.6 It is proposed that the fault ride through standard apply to generating plant commissioned after the effective date of the proposed Code changes. The cost of retrospective compliance with the requirements for existing wind generating plant is expected to be significantly higher than for new plant and the risk of trip of existing plant is effectively covered within the existing levels of reserve carried on the power system for credible event risks (refer to the System Operator's Policy Statement for a defined list of credible events).

4.1.7 Proposed Code changes to bring the proposal into effect are included in Appendix B.

Q3.	**Should the fault ride through standard apply to existing synchronous generating plant?**

4.2 Authority's objectives

4.2.1 The Authority's objective is set out in section 15 of the Act. Under section 32 of the Act, the Code may only contain provisions that are consistent with the objective and are also necessary or desirable to promote all or any of the following:

(a) competition in the electricity industry;

(b) the reliable supply of electricity to consumers;

(c) the efficient operation of the electricity industry;

(d) the performance by the Authority of its functions; and

(e) any other matter specifically referred to in the Act as a matter for inclusion in the Code.

4.2.2 The proposal contributes to the reliable supply of electricity to consumers by reducing the risk of generation disconnecting from the grid during grid faults. In addition, the proposal improves the efficient operation of the electricity industry by reducing the quantity of under frequency reserves required to protect against loss of injection from disconnected generation.

4.2.3 The proposal does not materially affect competition in the electricity industry, the performance by the Authority of its functions or other matters specifically referred to in the Act as a matter for inclusion in the Code.

4.3 Authority's code amendment principles

4.3.1 In accordance with the Authority's consultation charter, the Authority and its advisory groups, when considering amendments to the Code, will have regard to the following nine Code amendment principles to the extent that the Authority and its advisory groups consider that they are applicable:

(a) *Principle 1 – Lawfulness:* The Authority and its advisory groups will only consider amendments to the Code that are lawful and that are consistent with the Act (and therefore consistent with the Authority's statutory objective and its obligations under the Act).

(b) *Principle 2 – Clearly Identified Efficiency Gain or Market or Regulatory Failure:* Within the legal framework specified in Principle 1, the Authority and its advisory groups will only consider using the Code to regulate market activity when:

(i) it can be demonstrated that amendments to the Code will improve the efficiency of the electricity industry for the long-term benefit of consumers;

(ii) market failure is clearly identified, such as may arise from market power, externalities, asymmetric information and prohibitive transaction costs; or

(iii) a problem is created by the existing Code, which either requires an amendment to the Code, or an amendment to the way in which the Code is applied.

(c) *Principle 3 – Quantitative Assessment:* When considering possible amendments to the Code, the Authority and its advisory groups will ensure disclosure of key assumptions and sensitivities, and use quantitative cost-benefit analysis to assess long-term net benefits for consumers, although the Authority recognises that quantitative analysis will not always be possible. This approach means that competition and reliability are assessed solely in regard to their economic efficiency effects. Particular care will be taken to include dynamic efficiency effects in the assessment, and the assessment will include sensitivity analysis when there is uncertainty about key parameters.

(d) *Principles 4 to 9*: Principles 4 to 9, being tie-breaker principles to be used when the cost-benefit analysis is inconclusive, do not apply in this case.

4.3.2 The proposal is lawful to the extent that it is consistent with the Authority's statutory objective and its obligations under the Act.

4.3.3 The proposal is intended to contribute to the reliable supply of electricity to consumers and as such does not materially impact on market activity and is not intended to address any market failure.

4.3.4 The proposal includes a quantitative cost-benefit analysis in section 4.6 which assesses the long-term net benefits for consumers and includes details of key assumptions and sensitivities.

4.4 Objective of Authority's proposal

4.4.1 The objective of the proposed Code change is to ensure that the System Operator can continue to meet its principal performance objective to dispatch assets made available in a manner which avoids the cascade failure of assets arising from voltage excursions during transmission faults.

4.4.2 The Authority considers that the risk of cascade failure is increasing as new forms of generation are added to the power system and there is a need to add dynamic voltage performance obligations to the Code.

4.4.3 Section 39(2)(c) of the Act also requires the Authority to evaluate alternative means of achieving the objectives of the proposed Code change.

4.5 Alternative means of achieving the objective

4.5.1 The Authority considers the alternatives for achieving the objectives of the proposed Code change are:

(a) The proposal, discussed in section 4.1;

(b) Option A - the status quo, relying on the existing asset owner performance obligations in the Code for generator protection settings, voltage control systems and reactive power capability;

(c) Option B - a standard for both the North and South Islands based on the combined requirements of the System Operator's North and South Island proposals;

(d) Option C - a standard that matches the requirements already developed in other international grid codes.

Option A – The status quo

4.5.2 Option A places reliance for adequate under-voltage performance on existing obligations in the Code. These include:

(a) a requirement for grid connected generators to be operable over a range of grid voltages (± 10% for 220 kV and 110 kV, and ± 5% for 66 kV and 50 kV, clause 8.22(2));

(b) a requirement that protection systems operate selectively to disconnect the minimum amount of plant and preserve power system stability during faults (clause 4(4)(a)(ii) of technical code A of schedule 8.3);

(c) a requirement that generating units' voltage control systems be designed and have settings to support the System Operator in meeting the Principal Performance Obligations e.g. to avoid cascade failure during voltage excursions (clause 5(1)(a)(i) of technical code A of schedule 8.3); and

(d) a requirement for grid connected generators to provide reactive power capability over a range of grid voltages to support the System Operator in maintaining grid voltage within acceptable limits and secondly, to support the System Operator in maintaining voltage stability on the grid (clause 8.23).

4.5.3 As the existing voltage related obligations in the Code do not include dynamic performance standards, the objective of the Code amendment proposal could only be met under this option if:

(a) a performance standard was developed outside of the Code; and

(b) asset owners chose to comply voluntarily with the standard.

4.5.4 The dynamic voltage performance of generating plant can significantly affect the System Operator's ability to meet its principal performance obligation to avoid cascade failure. Compliance with the performance standard should not be voluntary and left to the discretion of asset owners. Accordingly, the status quo is not considered to be an acceptable option.

Option B – Combined standard for North and South Islands

4.5.5 Option B is a simplified variation of the proposal. It combines the North and South Island fault ride through envelopes described in the proposal to create a single composite standard to be applied across the whole country.

4.5.6 Of the two envelopes included in the proposal, the North Island envelope has the more onerous under-voltage performance requirement and the South Island the more onerous over-voltage requirement. A composite standard would combine these two sets of requirements to form a single combined standard applicable to the whole country.

4.5.7 Option B meets the objective of the Authority's proposal, but the advantages of a simplified standard would be potentially offset by an increase in compliance costs. It is not uncommon for fault ride through standards to be regionally based in the larger European and North American a.c. power systems. A regional approach provides greater flexibility to target future updates to the standard as the mix of connected generation and the performance of protection systems change over time.

4.5.8 By comparison, New Zealand's power grid is much smaller, but the inherently different dynamic voltage characteristics of its North and South Island a.c. systems (being isolated by the HVDC link) support a regional approach. The difference between the characteristics of the North and South Islands may become more distinct over time and a regional approach allows greater flexibility to update the standard, should the need arise in the future.

Q4. Do you agree that a single composite standard for both the North and South Islands is likely to result in increased compliance costs?

Option C – Standard used in another jurisdiction

4.5.9 This option would use a fault ride through standard developed by a jurisdiction which has already integrated large quantities of wind generation that could be considered to be generic or representative industry standard. It could be assumed that leading wind turbine manufacturers would have developed a level of compliance with the standards already in use in larger power grids.

4.5.10 There are many examples of existing fault ride through standards that could be adopted by New Zealand. A number of European countries including the Netherlands, Germany, Portugal, Spain, Germany and Denmark have significantly higher wind energy penetration levels than New Zealand and over the last five to six years grid authorities in these countries have developed their own fault ride through standards.

4.5.11 The System Operator surveyed the fault ride through standards used in the grid codes of 15 grid owners or countries in its literature review[7]. The under and over voltage requirements of these grid codes are shown in Figure 1.

4.5.12 The characteristics of the sample of ride through envelopes investigated follow a consistent general pattern. However, the variation in the detailed prescription of these standards indicates that jurisdictions have tailored their standards to suit the individual conditions of their grids. There is no one standard that could be considered to be a representative generic industry standard.

4.6 Costs and benefits of the proposal

4.6.1 While there has been no history of multiple non-faulted generating units tripping during major 220 kV faults, the risk of this occurring is increasing over time as more non-synchronous generation is connected to the power system. The Authority is concerned that the current arrangements, if retained, will eventually lead to cost increases to the industry arising from:

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

(a) increases in the quantity of under frequency reserves required to protect against the loss of injection from non-faulted generating plant[8];

(b) restrictions on the types of generation development in some geographical regions; and

(c) increased risk of consumer disconnection.

4.6.2 Although it is difficult to quantify the economic costs arising from (b) and (c), it is possible to assess the avoided cost of procuring additional reserves, assuming that fault ride through standards are introduced. The avoided cost (as a benefit) can be compared with the compliance cost for generators to meet the proposed standard.

4.6.3 It is proposed that the fault ride through standards apply to all types of generation although only non-synchronous generators, which are predominantly used for wind generation, will face compliance costs.

4.6.4 The assessment of costs and benefits is sensitive to assumptions about the future levels of wind penetration. The Electricity Commission developed the four wind generation development scenarios described in Table 3 which it used for studies carried out under the WGIP. Net present value (NPV) calculations were carried out for a range of wind penetration levels including WGIP scenarios A, B and C[9]. Wind penetration levels were assumed to ramp up to the target levels over a 10 year period and no further increases were assumed beyond the 10 year horizon.

Table 3: Wind generation development scenarios

Island	Scenario A high, concentrated NI	Scenario B high, diversified across NZ	Scenario C v. high, diversified across NZ	Scenario D low, diversified across NZ
North Island	1150 MW	950 MW	1600	370
South Island	100 MW	300 MW	650	50

Source: Electricity Commission summary report: Effect of large scale wind generation on the operation of the New Zealand power system and electricity market, June 2007

[8] The loss of non-faulted generating plant is not currently factored into the contingent event risk in the System Operator's security policy (refer to chapter 1 of the Policy Statement in clause 8.9)

[9] The current level of wind penetration in New Zealand has already exceeded scenario D.

Q5.	Do you agree that the WGIP wind generation scenarios are appropriate for the NPV analysis?

4.6.5 The current levels of installed wind capacity are 437 MW in the North Island, with another 80 MW under construction, and 61 MW in the South Island. Approximately 4000 MW of wind generation projects are under investigation.

4.6.6 NPV calculations are summarised in Figure 4 and Table 5.

4.6.7 The input assumptions for the calculations are outlined in Table 4 below:

Table 4: Inputs for NPV calculations

Input Assumptions	North Island	South Island
2010 base year installed wind generation capacity	437 MW	61 MW
Wind generation capacity factor	40%	40%
Average contingent event risk excluding wind generation	350 MW	100 MW
Total installed wind turbine cost/MW	\$2.42 m	\$2.42 m
Increase in turbine cost for fault ride through compliance[10]:	1.25%	1.25%
Fast instantaneous reserves (FIR) required to cover 1 MW of wind turbine risk	0.9 MW	0.9 MW
Average cost of FIR/MWh	\$5	\$3
Sustained instantaneous reserves required to cover 1 MW of wind turbine risk	1 MW	1 MW
Average cost of SIR/MWh	\$5.4	\$1
NPV discount rate	7%	7%

Sources:

Turbine costs - European Wind Energy Association – The Economics of Wind Power, 2010

Wind turbine fault ride through compliance cost – based on recent New Zealand project

FIR and SIR costs - averaged actual costs from 2007 to 2010

[10] NPV calculations use 1.25% for 2011, ramped down to 0% by 2020. The basis of this assumption is that compliance costs will decline over time as full scale converter technology becomes a standard feature of grid connected wind turbines.

Figure 4: NPV variation with wind penetration level

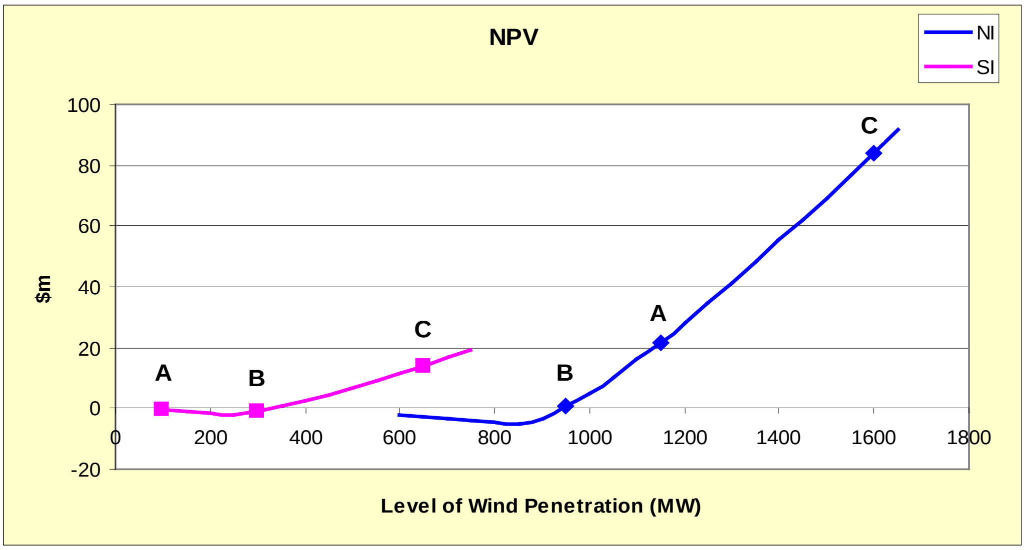


Table 5: NPV summary for wind scenarios

Wind Scenario	North Island	South Island	Total
A (high, concentrated NI)	$ 22 m	($ 0.5 m)	$21.5 m
B (high, diversified across NZ	$ 0.5 m	($ 1m)	($ 0.5 m)
C (very high, diversified across NZ)	$ 84 m	$ 14 m	$ 98 m

Q6.	**Do you agree with the Authority's input assumptions for the NPV calculations? If not, please provide alternative input values.**

4.6.8 Ignoring the aspects of the proposal relating to short circuit reactive current and short circuit power contribution during faults, the NPV analysis does not support fault ride through standards at low levels of wind penetration. The analysis indicates that it would be uneconomic to incur the compliance costs of fault ride through standards at low wind penetration levels because the risk of non-faulted generating plant tripping during voltage disturbances can be covered by the quantity of reserve already carried to manage identified contingent events.

4.6.9 The analysis suggests the proposed fault ride though standard will result in a positive net benefit if the ultimate levels of wind penetration exceed 950 MW in the North Island and 350 MW in the South Island. These levels correspond closely to scenario B used in the WGIP investigations.

4.6.10 The probability of the wind penetration level reaching or exceeding scenario B in the next 10 years is considered to be moderate to high. Scenario B levels would be exceeded if 20% of the 4000 MW of wind farm projects currently under investigation were developed through to commercial operation.

Q7. Do you agree that there is a moderate to high probability of scenario B wind penetration levels being reached in the next 10 years?

4.6.11 Some additional benefit could be achieved by delaying the introduction of fault ride though standards until the time when additional reserves would be required to cover the risk of non-faulted generating plant tripping during voltage disturbances. The period of the delay that could be accommodated is sensitive to assumptions made about future levels of wind penetration and the timing of large projects. Any new wind farm in excess of 350 MW would require some additional reserves to be purchased from the time it was commissioned. Four projects of this size or larger are currently under investigation. Depending on theses factors, an acceptable period of delay could range from one to eight years.

4.6.12 A provision could be added to the proposed Code changes to trigger an effective date for the introduction of the proposed standards at a time when levels of wind penetration exceed 950 MW in the North Island and 350 MW in the South Island. Generating plant commissioned after the effective date would be required to comply with the proposed standards.

4.6.13 Given the difficulty of determining an optimum period of delay for the introduction of the standards and the regulatory uncertainty delay creates for generation investors, it is not recommended that the effective date of the proposed standards be delayed.

Q8. Do you agree that there would be benefits in proceeding immediately with proposed fault ride through standards or should the effective date of the proposed standards be triggered at a future date by the level of wind generation penetration?

4.7 Assessment against the objective

4.7.1 There are currently no performance envelopes specified in the Code for asset owners to ensure their generating assets remain transiently stable and connected to the power system during voltage disturbances that arise from system faults. The objective of the proposal is to improve the System Operator's ability to manage its obligation to avoid cascade failure during voltage disturbances arising from system faults.

4.7.2 The proposal is to establish specific fault ride through standards for the North and South Islands which would ensure that non-faulted generating assets remain stable and connected during faults and thereby avoid the risk of large scale loss of power injection into the grid.

4.7.3 The assessment of the benefits and costs of the proposal supports the proposal on the assumption that the quantity of grid connected wind generation grows as expected.

4.7.4 The Authority's initial view is that the proposal best meets the objective as it would:

(a) minimise the risk of large quantities of wind generation disconnecting from the power system during system faults;

(b) avoid the need to purchase additional reserves to manage the risk of large quantities of wind generation disconnecting from the power system during system faults; and

(c) provide a set of standards tailored for power system conditions in the North and South Islands.

Q9.	**Do you agree with the Authority's overall assessment that the proposal best meets the objective of the proposal?**

4.8 Conclusion

4.8.1 The Authority is concerned that the risk of voltage or frequency instability on the power system is increasing as the mix of generation on the power system changes over time. This risk can be managed by placing obligations on non-faulted generating assets to remain connected and ride through periods of voltage disturbances during and following a fault.

4.8.2 The preferred approach is to require non-faulted generating assets to remain transiently stable and connected to the power system without tripping while system voltage remains within a defined under and overvoltage envelope following a fault on the transmission system. Separate envelopes are proposed for the North and South Islands.

4.8.3 Before finalising this approach, the Authority wishes to consider the views of stakeholders and in particular in relation to the questions listed in this paper and summarised in Appendix A.

Appendices

Appendix A Format for submissions

Question No.	General comments in regards to the:	Response
Q1	Do you agree with the System Operator's modelling assumptions and study methodology?	
Q2	Should the fault ride through standard apply to generating stations smaller than 30 MW?	
Q3	Should the fault ride through standard apply to existing synchronous generating plant?	
Q4	Do you agree that a single composite standard for both the North and South Islands is likely to result in increased compliance costs?	
Q5	Do you agree that the WGIP wind generation scenarios are appropriate for the NPV analysis?	
Q6	Do you agree with the Authority's input assumptions for the NPV calculations? If not, please provide alternative input values.	
Q7	Do you agree that there is a moderate to high probability of scenario B wind penetration levels being reached in the next 10 years?	
Q8	Do you agree that there would be benefits in proceeding immediately with proposed fault ride through standards or should the effective date of the proposed standards be triggered at a future date by the level of wind generation penetration?	
Q9	Do you agree with the Authority's overall assessment that the proposal best meets the objective of the proposal?	

Appendix B Proposed Code changes

This Appendix presents the amendments proposed to the Code.

1. Add the following clauses to subpart 2 of part 8 of the Code.

Generator fault ride through performance obligations

8.20A Fault ride through

(1) Each **generator** must ensure that its **assets**, when connected, remain transiently stable and connected without tripping any **generating unit** within the no-trip envelope shown in Figure 1 or Figure 2 (as applicable) during a solid three-phase short circuit fault or any unbalanced short circuit fault on any part of the **grid** at voltages of 110 kV or 220 kV.

(2) A **generator** is not required to comply with subclause (1) if clearing the fault would effectively disconnect the **generating unit** from the **grid**.

(3) A **generating unit** may trip 3 seconds or more after initiation of a fault on the **grid**, as described in subclause (1), if this action is an intentional part of a special protection system.

Figure 8.1: North Island fault ride through envelope

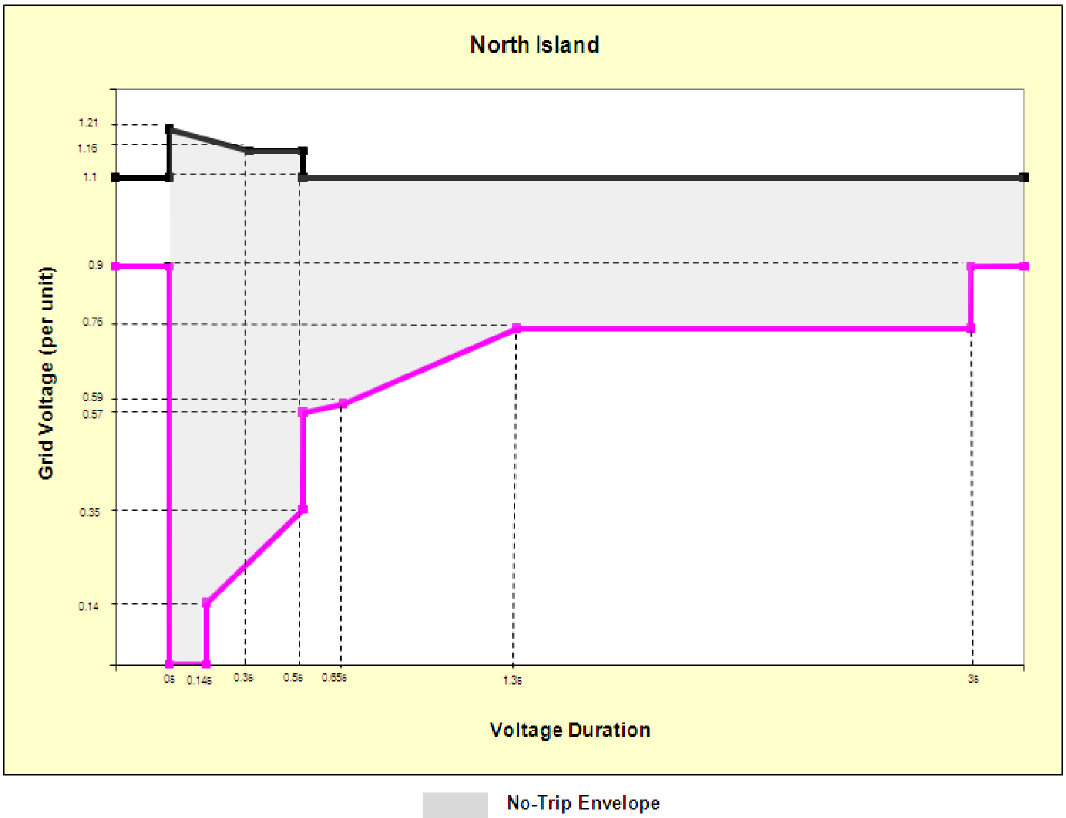
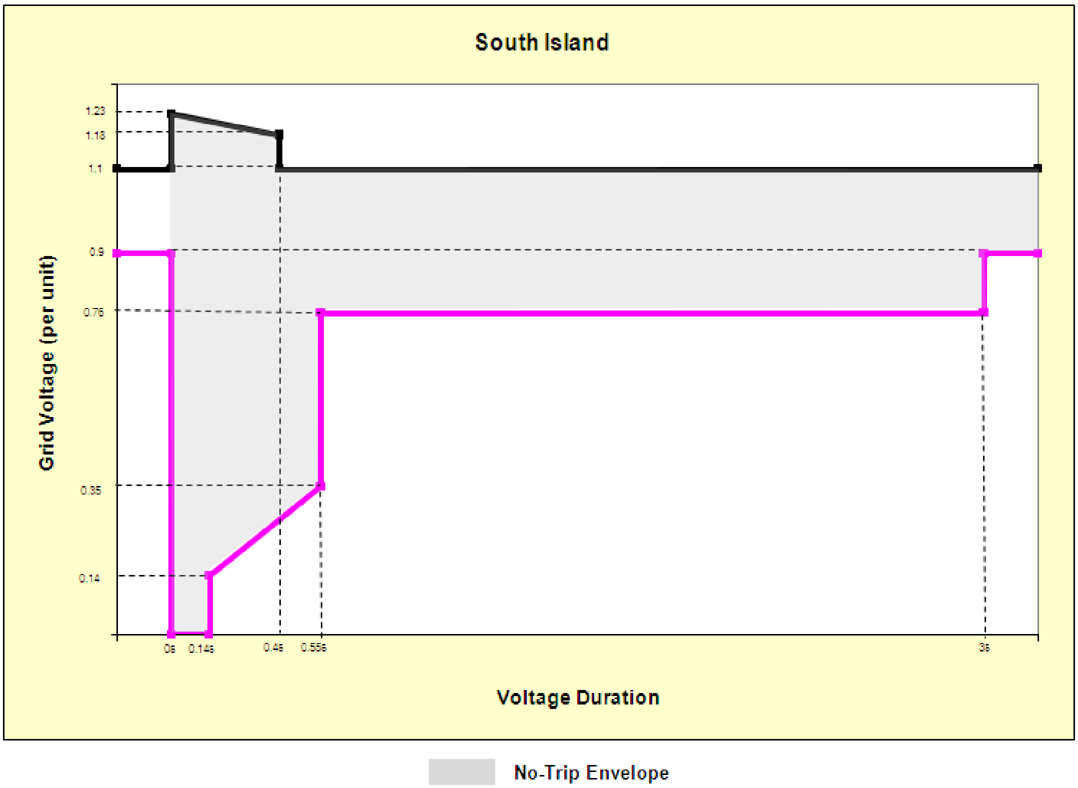


Figure 8.2: South Island fault ride through envelope



8.20B Reactive current and active power output

(1) Each **generator** must ensure that each of its **generating units** generates maximum reactive current without exceeding the **generating unit's** transient rating limit during the period of a fault on the **grid** as described in clause 8.20A(1).

(2) Each **generator** must ensure that each of its **generating units,** relative to pre-fault **active power** output, provides **active power** output at least in proportion to the retained balanced voltage at the **grid injection point** following clearance of a fault on the **grid** as described in clause 8.20A(1).

(3) Subclause (2) does not apply to a **wind generating station** if there has been a reduction in the intermittent wind power source during the time range in Figure 1 or Figure 2 as applicable.

8.20C Use of additional equipment

A **wind generating station** may meet the requirements of clause 8.20A by—

(a) the performance of the **generating units**; or

(b) installing additional equipment within the **wind generating station**; or

(c) a combination of **generating unit** performance and additional equipment.

8.20D Application

(1) A **generating unit** is not required to comply with clauses 8.20A and 8.20B for its remaining life if,—

(a) on the date on which this clause comes into effect, the **generating unit** is connected; or

(b) the **generating unit** has been connected prior to the date on which this clause comes into effect.

(2) Despite subclause (1), if a **generating unit** described in subclause (1)—

(a) at any time after the date on which this clause comes into effect, complies with clauses 8.20A and 8.20B, it must comply with clauses 8.20A and 8.20B for the remaining life of the **generating unit**:

(b) is subsequently replaced, the replacement **generating unit** must comply with clauses 8.20A and 8.20B.

(3) Clauses 8.20A and 8.20C do not apply to—

(a) a **wind generating station** when it operates at less than 5% of rated **MW**:

(b) a **generating unit** at an **excluded generating station**.

2. Amend clause 8.21 of the Code as follows:

Excluded generating stations

8.21 Excluded generating stations

(1) For the purposes of clauses 8.17, 8.19, 8.20D and the provisions in **Technical Code** of Schedule 8.3 relating to the obligations of **asset owners** in respect of frequency……..

Appendix E Summary of submissions on February 2011 Fault Ride Through Consultation Paper

General comments

Submitter	Submitter's comment	Response
Genesis	Genesis Energy recommends that the implementation of the proposed fault ride through standards be delayed until the effect of Pole 3 can be determined. Pole 3 is already under construction and will be a significant change to the operation of the national electricity grid, yet the Authority did not include it within its analysis. We believe Pole 3 should be able to provide voltage support for the loss of Pole 2 and is therefore likely to lessen the requirement for the proposed fault ride through standards. Genesis Energy is concerned that the Authority is seeking to introduce a change to the Electricity Industry Participation Code ("the Code") without having a clear understanding of whether such a change is needed in the immediate future. Introducing overly stringent standards earlier than perhaps needed, then signalling a review of those standards after 2012 will only create regulatory uncertainty and hamper the investment decisions of generation developers. Further robust analysis of the effect of Pole 3 will also ensure that this Code change meets the Authority's requirements for Code amendments, in particular: • principle 2 that stipulates that there must be a clearly identified efficiency gain or market or regulatory failure • principle 3 that requires a quantitative assessment of the long-term net benefits for consumers. At present, it is uncertain whether there will be an efficiency gain in the operation of the electricity grid from the proposed fault ride through standards when Pole 3	The system operator assessed the effect of the loss of Pole 3 (700 MW) on an n-1 basis, along with other credible contingencies. The presence of Pole 3 has no impact on the transient under voltage requirements and considerably worsens the transient over voltages from a bipole trip. The effect of Pole 3 was taken into account in the assessment.

Submitter	Submitter's comment	Response
	is commissioned and the quantitative assessment of the long-term net benefits for consumers does not incorporate the effect of Pole 3.	The efficiency gain in the operation of the electricity market has been demonstrated in the assessment and the effect of Pole 3 taken into account.
NZWEA	The system pperator's analysis has identified that system voltage stability can vary significantly around different regions and for different network voltages. The proposed envelopes represent a generalised and conservative view of the performance that is required. In some instances delivering the proposed envelope may add unnecessarily to system cost, or may see an opportunity missed for delivering a solution that provides an overall better outcome (for example in the application of reactive power). Consideration should be given for making the envelope a default position where the generator and system operator can negotiate an alternative outcome where this gives a better overall performance at equal or lesser cost (i.e. the negotiated outcome should be no more costly or more onerous in terms of performance than the default envelope). We understand that such provisions are made available in other markets. (NZWEA's wind turbine manufacturer members may be able to identify suitable references.)	The proposed fault ride through Code amendment would be subject to the dispensation and equivalence provisions in section 8 of the Code that give a generator the option to negotiate an alternative outcome with the system operator.
Philip Wong Too	Section 2.1.3 implies that there are specific requirements within the Code for generators to remain connected during under frequency and over frequency events. In my reading of the Code, while the requirements to remain connected during certain under frequency events is explicit within the code, there is no explicit requirement to remain connected during an over frequency event. I would suggest that codifying the requirement to remain connected during over	Clause 8.19 of the Code requires generators to remain connected at all times when the frequency is above 47.5 Hz (NI) or 47 Hz (SI).

Submitter	Submitter's comment	Response
	frequency events could be a subject for the Electricity Authority to consider, if this is important for system security.	
Philip Wong Too	Section 4.1.1(b) "maintain mechanical power output during and following a fault to avoid loss of power generation to the grid". This fails to recognise that active power injection from a generator into the grid inherently reduced during a fault. If mechanical power is maintained, this will result in acceleration of the machine (unless the "surplus" active power is dissipated in another means) which could result in the machine suffering an over speed trip. Thus, depending on the wind turbine design, it might be necessary to reduce the mechanical (aerodynamic) power output to maintain control of the machine.	The proposed Code amendment clarifies that power output is required to be maintained in proportion to the grid voltage following clearance of the fault.
Transpower	We are very supportive of the technical work presented in this consultation paper and its application to New Zealand. However, since the system operator carried out this work, the grid owner has brought to its attention issues related to certain known HVDC events (specifically bipole trips and events that cause a bipole 'block') and the need to consider the implications of these for areas in close proximity to the HVDC. This has highlighted that there may be regions of the network where a more onerous requirement is necessary for connection to achieve the same level of Common Quality. In these cases, these regions and their envelopes would need to be specified separately, or, alternatively, Common Quality requirements met in other ways, such as by purchasing greater reserves. We have already begun discussions with the Authority on this matter and expect to resolve this issue with the Authority at a later date.	The updates to the original fault ride through standards in this consultation paper reflected in the supporting Code address this issue.
Trustpower	Given the location specific nature of voltage issues Trustpower feels it appropriate that Asset Owners and the system operator retain the ability to apply for and grant dispensations where appropriate.	Dispensations and equivalence would apply to the proposed Code amendment.

Submitter	Submitter’s comment	Response
Trustpower	A key reason for the initiating the review was based on the GFRT studies undertaken by the Wind Generation Investigation Project (“WGIP”). These studies found that GFRT may become an issue if a significant amount of synchronous generation was “displaced” by wind generation that contained no GFRT capability. To date what has happened is that wind generation has actually “complemented” as opposed to “displaced” synchronous generation. Another key assumption made throughout all of the WGIP studies was that all new wind generation would be from simple induction generators and therefore have no GFRT capability. In reality, this has proven to be very pessimistic as none of the wind farms greater than 30 MW that have been commissioned in New Zealand since the WGIP study was undertaken have used simple induction generators. In fact all of them have consisted of either, synchronous machines, doubly fed induction generators with statcoms or full scale converter machines. Upon reading the detailed analysis undertaken by the system operator Trustpower also formed the opinion that the voltage issues facing New Zealand are not solely as a result of the ratio between synchronous and non-synchronous generation but also related to the rate at which load growth has exceeded transmission investment over time. Trustpower considers the information provided regarding the NPV analysis to be somewhat lacking and therefore ambiguous. However, despite whose assumptions are used, Trustpower does not expect the outcome to be materially different. Further to this, when compared to the financial implications regarding frequency management we consider this to be relatively insignificant.	Wind generation that is unable to ride through system faults remains a risk whenever it is connected to the grid whether is considered to complement or displace synchronous generation. It cannot be assumed that all non-induction type wind generators have the required fault ride through capability. The characteristic of the transient under voltage profile is determined by the performance of protection systems and the characteristics of the load, rather than the ratio between synchronous and non-synchronous generation.

Submitter	Submitter's comment	Response
Trustpower	Trustpower does not understand the rationale behind the comments in paragraph 4.6.3 of the paper regarding exempting synchronous generation from compliance costs. Trustpower is clearly of the view that all generation technologies need to be treated in an equal manner.	Para 4.6.3 expresses the view that synchronous generation will not face compliance costs because it is likely to be compliant, not because it is proposed to exempt synchronous generators from compliance costs (refer to the application provisions in clause 8.20D of the proposed Code amendment.
Vestas	Vestas acknowledges the need that all proposed projects on the network require system stability performance to be evaluated. However, the efficiency of the network system may best be served by evaluating the voltage requirements of each project on a case by cases basis rather than compliance to an overriding generic fault ride through envelope requirement. In our view, the effect of the proposed changes to the Code may induce the potential for allocation of reactive support in locations on the network that may not fully benefit from such installation, hence creating less efficient economic benefits to the network as a whole and to end users. The EA's consultation paper investigates and compares fault ride through requirements in electrical codes in a number of overseas markets. It should be noted that many of those codes operate in power systems where such technical standards may be customised to a level that is optimal for the specific	This suggested arrangement would be impractical to administer given the extent of analysis required on a case by case basis for each potential generation proposals. Investigation of other markets indicated this approach is not commonly in overseas jurisdictions. Dispensations and equivalence provisions in the part 8 of the Code allow for this possibility.

Submitter	Submitter's comment	Response
	connection point that is being evaluated. Unfortunately, it appears that the EA's proposed Code changes are silent on such customisation.	
Windflow	The consultation paper does not explore acceptable methods for proving compliance of commissioned assets. While a manufacturer's type test might indicate a certain level of fault ride through capability for a generating unit under a particular set of circumstances, a completed generating station will experience significantly different dynamic voltage profiles dependant on the number and type of generating units, collection and reticulation network parameters, relative location of station assets, and transformer characteristics. What will be the means for assessing compliance of a generator's assets with the proposed code changes?	While it is accepted that proof of compliance is difficult to assess across a completed wind farm, fault ride through is no different in this respect to other AOPOs such as generators under-frequency performance.

Q1. Do you agree with the system operator's modelling assumptions and study methodology?

Submitter	**Submitter's comment**	**Response**
Contact	Excluding Pole 3 makes the analysis of the future situation largely invalid as shortly the HVDC will be the critical contingency, (making the analysis redundant).	The effect of the loss of Pole 3 (700 MW) was assessed on an n-1 basis, along with other credible contingencies.
Genesis	Genesis Energy believes the assumptions and study methodology selected by the system operator appear appropriate. However, it is difficult to judge the impact of alternative assumptions on the study, given that only high-level information is provided in the consultation paper.	References are provided in the consultation paper to more detailed investigation reports produced by the system operator.
NZWEA	NZWEA generally agrees with the assumptions and methodology applied. We note however that the system operator's report advises that their proposal for the North Island "*would need to be reviewed once the planned upgrade for additional dynamic plant in the Upper North Island is approved and commissioned*" (section 4.8.1, page 17). It appears from related comments that the profile after these upgrades would look more like that for the South Island. Adopting the proposed profile would appear to be a conservative approach, which may ultimately increase compliance costs unnecessarily. We also note that a key driver of the profile beyond about 1 second is the ride-through performance of the HVDC system. It is unclear from the report if this reflects the performance of the existing system or the pending system including the new Pole 3. NZWEA is unsure if any change in performance is expected with	It is possible that future additional dynamic reactive plant may lessen the under voltage profile requirement, but equally, changes in the characteristics of load may increase the requirements. The effect of the loss of Pole 3 (700 MW) was assessed on an n-1 basis, along with other credible contingencies.

Submitter	Submitter's comment	Response
	Pole 3 that might need to be considered in establishing the future generation ride through requirements. As above, an overly conservative approach could ultimately unnecessarily increase generation costs. The system operator report notes at section 2.3 that it assumes in its modelling that all existing wind farms are "unavailable" as they may not remain connected for close-in faults (page 8). Again this would seem to be a very conservative approach (especially when modelling faults in the upper North Island, for example). Much of this plant does have equipment fitted that would allow it to stay connected through at least some fault events (especially Project West Wind, as the report itself identifies). The report demonstrates that a wide range of profiles exist, depending on the characteristics of the system in the particular region. Basing the proposed ride through profiles around the "worst case" scenarios may then result in the installation of ride through capability that may not actually be required (while at the same time perhaps also missing out on opportunities to agree specific system performance – in areas such as reactive power – that might actually provide a greater overall benefit to system security in that region).	The ride though performance of existing wind farms is unknown. There is no guarantee that any existing ride through capability is currently enabled. Dispensations and equivalence provisions in the part 8 of the Code allow for this possibility.
Repower Australia Pty Ltd	It is unclear how big the risk of the worst case scenarios is. Also, it is unclear whether the worst case scenarios have ever occurred and how the grid responded.	AOPO performance obligations are generally calculated from the worst case than can arise and are not moderated by probability considerations.
Todd	The system operator's modelling assumptions would seem reasonable following	

Submitter	Submitter’s comment	Response
	a brief review of the detail in the SO report. However we would question whether the grid owner and system operator should be more proactive in verifying and producing a more accurate power system model of the dynamic characteristics of connected load at the key GXPs, noting that *“the nature of the load has the greatest impact on system performance under faulted conditions”* (paragraph 2.4.4 from the paper). There is little qualitative background information provided on the accuracy of the load model, and we would query whether the GO/SO is collecting adequate high-speed data in an effort to verify the dynamic load model under system disturbances. The SO/Code requires other asset owners (e.g. Generators) to provide very accurate dynamic models at considerable collective cost, and this costly accuracy becomes watered down from a system dynamic model perspective unless the load model accuracy is comparative.	The best load modelling information available at the time, based on consumer surveys, was used in the studies.
Transpower	Yes.	Noted.
Trustpower	Trustpower agrees with the system operator’s reasoning for using the summer peak in assessing the transient under voltage conditions. The performance of the system following an HVDC fault appears to be a significant factor in determining the “tail” of the proposed transient under voltage component of the envelopes. This is of particular concern to some manufacturers of Doubly Fed Induction Generator (“DFIG”) based equipment. Given that the system operator’s study was undertaken in late 2009, early 2010, it is unclear if Pole 3 of the HVDC has been allowed for and, if so, whether the system’s performance improves or deteriorates as a result. Upon reading the system operator’s report it appears as if the transient under	The HVDC is not a significant factor in determining the tail, it is load recovery that most affects the tail.

Submitter	Submitter’s comment	Response
	voltage performance of the system is expected to deteriorate over the next few years more as a function of load growth than from the displacement of synchronous generation sources or the deterioration in the performance of the generation fleet. For the purposes of the study Trustpower agrees with the top down approach adopted by the system operator. However, given that voltage issues are often localised in various parts of the grid, from an implementation perspective Trustpower sees real merit in the system operator continuing to undertake location specific fault studies to determine the real impact and use the dispensations process if appropriate.	This is the case on localised parts of the grid at voltages below 220 kV and 110 kV. The effects at 220 KV and 110 kV are widespread and the proposal is intended to apply to generation connected at these higher voltages.
Vestas	It appears that some assumptions have been made including some averaging of results that may overestimate the true nature at different locations within the North and South islands. The effect of faults will be varied at different locations on the network. Hence, the creation of an envelope for the entire network may overemphasise the true need at specific locations. It is also noted that a summer peak load condition was used in the determination of the transient envelope. This assumption may overemphasis the true economic benefits over the year.	This will always be the case if a single fault ride through standard is applied to each a.c. power system. It is not possible to apply different fault ride through standards for different times of the year.
Windflow	The assumptions and methodology used to determine the proposed fault ride through voltage envelopes appear to be valid.	Noted.

Q2. Should the fault ride through standards apply to generating stations smaller than 30 MW?

Submitter	Submitter's comment	Response
Contact	No. This could act as a barrier to investment in generation <30 MW.	Noted.
Genesis	No. A small station (or a group of small stations) tripping is unlikely to have a significant impact on the performance of the grid and the cost to small generation plants to meet these standards would likely outweigh any potential benefits. In addition, many small plants using technology other than wind already have the ability to stay connected during faults (for example, diesel plants).	Noted.
Meridian	Meridian does not support the fault ride through standards applying to generating stations smaller than 30 MW. In Meridian's view, this sets a preference for small power stations, effectively penalising large power stations. Meridian is concerned that this is likely to incentivise low quality small wind farms.	It is likely that the fault ride through standards would have a small effect on the size and type of wind farm development relative to other assessment factors.
NZWEA	NZWEA agrees that this would appear to be a reasonable threshold for specifying these performance standards. Projects below this size are unlikely to have a significant effect on transmission system dynamics. We note that projects of this size are likely to be connected within lines networks rather than to the transmission system and the owners of these networks may require certain levels of protection and performance if the wind farms could have a significant impact on network performance. The cost of a hardware solution to ensure that these standards are achieved, such as a STATCOM, would add significant cost to a small project of this nature	Noted.

Submitter	Submitter's comment	Response
	and so is potentially a barrier to market entry.	
Todd	No. In the same manner as frequency requirements, "excluded generation stations" should not be required to meet the fault ride through standards. Further, it is unclear from the Paper (refer paragraphs 4.1.4 and 4.1.5) and the proposed Code changes (proposed clause 8.20A(1)) whether a generator that is connected to the grid or local network at a connection voltage less than 110kV is required to meet the no-trip-envelope of the fault ride through standards, from which it would otherwise seem hard to assess compliance from a practical sense.	Noted. Generating stations larger than 30 MW would be required to comply with the proposed Code change regardless of connection voltage.
Transpower	No. However, there needs to be an ability for the system operator to request the Authority, on a case by case basis, to require excluded generators to comply with the fault ride through requirements.	Agreed, the proposal has been revised to provide this option to the system operator.
Trustpower	No. Trustpower firmly believes there are numerous reasons why stations less than 30MW should be considered as Excluded Generating Stations. For example: • The cost to connect stations of less than 30MW to the Grid is such that the majority of stations less than 30 MW are, and will continue to be, embedded within distribution networks where it has been identified that the impact of low voltage events is somewhat attenuated. See paragraphs 2.4.8 and 2.4.10. • As this Code change applies to all forms of generation, not only wind powered generation, the EA must be mindful of the impacts this would have on other forms of non-synchronous distributed generation, such as, but not limited to, hydro based induction machines and the like. If stations less than 30MW were subject to the proposed GFRT provisions	Noted.

Submitter	**Submitter's comment**	**Response**
	then paragraph 4.6.3 implies that small hydro based induction machines would face compliance costs. • The cost of providing GFRT by the provision of STATCOM type devices is not linear. That is the cost per unit of STATCOM based GFRT capability generally reduces as the size of the plant increases. • The cost of providing GFRT for sites of less than 30 MW would be considered as a definite barrier to entry. •	
Vestas	FRT standards should not apply to generating stations smaller than 30 MW as smaller generation plants generally have a lesser impact on network stability.	Noted.
Windflow	The fault ride through standards should not apply to stations smaller than 30 MW due to these stations' limited impact on dynamic grid performance.	Noted.

Q3. Should the fault ride through standards apply to existing synchronous generating plant?

Submitter	Submitter's comment	Response
Contact	No as the proposed code changes are addressing the risk of wind generation not riding through a fault, existing synchronous generating plant - as a whole - are not considered a risk. The concern is that if a grandfathering arrangement is provided, that: • There will be a need to prove fault ride through at some stage. This could mean a generator may incur compliance costs associated with asset testing from that time; and • If code compliance is demonstrated through a system event, a generator may then be required to start asset testing, and could incur associated compliance costs. To this end we proposed clause 8.20D (2) (as shown below) should be removed. (*2) Despite subclause (1), if a generating unit described in subclause (1)—* *(a) at any time after the date on which this clause comes into effect, complies with clauses 8.20A and 8.20B, it must comply with clauses 8.20A and 8.20B for the remaining life of the generating unit:* For the under voltage requirement, we have concerns with the proposal that a machine should ride through zero volts. The potential issue is under-voltage over-current protection (51V) operating, why not make the p.u. equivalent 5kV (L-L on 220KV)?	The purpose of proposed clause 8.20D (2) is to ensure that assets currently compliant with the proposed standards remain so and that performance does not degrade over time. The intention is that generating units should be able to ride through a solid high voltage fault on a nearby bus or line. The requirement applies at the HV bus, not the generating unit terminals.
Genesis	No. Genesis Energy notes that the cost of retrofitting existing generation plant, particularly large thermal plant with significant auxiliary supplies would be prohibitively expensive. We recommend that generation plant under construction	Noted.

Submitter	Submitter's comment	Response
	or contract when the standards are introduced should also be exempt from the proposed fault ride through standards. It would be extremely expensive to change generation plant specifications at the detailed design or construction phase. This exemption could be achieved by providing a suitable lead in period for the proposed standards.	
MEUG	No. Retrospective application of new standards should be avoided if possible unless there are large benefits to do otherwise. The latter caveat does not apply in this case for existing wind farms. The policy problem arises as new wind farms are built and the policy solution should be targeted accordingly.	Noted.
Meridian	No. In Meridian's view, the cost of checking the performance of existing plant is likely to be significant. However since it is existing plant that sets the largest risks, Meridian submits that we ought to move to having plant such as Huntly at approx. 1400MW and Manapouri at 840 MW to ride through faults as defined in the document and comply. Meridian recommends that the Code is changed so that as units are replaced they shall then be required to comply with these standards.	Noted. This risk is already covered through instantaneous reserve and AUFLS. Fault ride through standards are intended to manage risks that could be larger than the single largest risk. This provision is already included in proposed clause 8.20D(2)(b).
NZWEA	No. The standards should not apply to any existing generators (synchronous or non-synchronous). The cost of determining whether these generators comply or	Noted.

Submitter	Submitter's comment	Response
	not, and of retrofitting any necessary equipment to bring them up to the standards are not likely to outweigh the benefits. It is however appropriate that the overall performance of the generation fleet is brought up to the required standards over time where this is practical. In this respect the text in the proposed code changes that requires any replacement generators on existing stations to meet the standards is appropriate.	
Todd	No. We strongly support the proposed Code change in the context that existing synchronous generation units are not required to comply as it is the expected future increase in wind generation connected to the power system that is driving the need for the standards. It is unreasonable to push these compliance costs onto existing synchronous generators. Todd Energy has interests in a number of existing co-generation plants where, within reason, security of supply to the on-site factory load is paramount and the economic basis for the investment in co-located generation. These installations need to maintain the ability to isolate from the grid in the event of significant transient disturbances where there is otherwise undue risk and cost should total loss of supply to the factory occur. Furthermore, the Authority's CBA would indicate there are no benefits in the immediate introduction of the standards so it would seem reasonable that only generation plant connecting in the future need comply, and investors can factor these compliance costs in plant selection.	Noted.
Transpower	Yes, it should apply to all synchronous generating plant.	Noted.

Submitter	Submitter's comment	Response
Trustpower	No. However, to avoid possible confusion it should also be made clear that the proposed GFRT standards should not apply to any existing generation plant - as opposed to any existing synchronous generating plant as proposed. Despite it being unrealistic to impose this requirement on existing synchronous machines it is also understood that in general New Zealand's existing fleet of synchronous generators perform relatively well during transient under and over voltage type events. This is also reinforced by paragraph 3 of the Executive Summary. The studies undertaken by the WGIP also found that GFRT may become an issue if a significant amount of synchronous generation was "displaced" by wind generation with no GFRT capability. To date what has happened is that wind generation has actually "complemented" as opposed to "displaced" synchronous generation. It should also be noted that the WGIP studies assumed that all new wind generation would be from simple induction generators and therefore have no GFRT capability. In reality, this has proven to be very pessimistic as none of the wind farms greater than 30 MW that have been commissioned in New Zealand since the WGIP study was undertaken have used simple induction generators. In fact all of them have consisted of either, synchronous machines, Doubly fed Induction Generators ("DFIG") with STATCOMS or full scale converter machines.	Clause 8.20D of the proposed Code amendment makes it clear that the fault ride through standards should not apply to any existing generating plant. However, 8.20D includes an obligation that assets currently compliant with the proposed standards remain so and that performance does not degrade over time.
Windflow	The fault ride through standards should not apply to any existing generating plant. While Windflow anticipates that all of its existing generating units in their	Noted.

Submitter	Submitter's comment	Response
	current configuration would comply with the proposed standards, retrospective compliance costs for many other existing generator assets would likely exceed the benefits attained.	

Q4. Do you agree that a single composite standard for both the North and South Islands is likely to result in increased compliance costs?

Submitter	Submitter’s comment	Response
Contact	Yes, it is more optimal to tailor to the requirements of each island.	Noted.
Genesis	Yes	Noted.
Meridian	No. Meridian supports the two standards.	Noted.
NZWEA	Yes. As discussed above, even the generic standards for the North and South Islands may increase compliance costs for generators in locations where a specific profile might be more appropriate.	Noted.
Todd	It would seem a reasonable assumption.	Noted.
Transpower	Yes	Noted.
Trustpower	When compared to the status quo, yes. However, when compared to the proposed individual North and South Island standards Trustpower does not expect the costs to be significantly different. On checking with one of the leading suppliers it was determined that the most onerous part of the proposed envelope for them to comply with occurred on the under voltage transient curve approximately 2 seconds after the initiation of the event. As the requirements of the North and South Island curves are identical after 1.3 seconds the impact on this particular supplier would be the same for	Noted.

Submitter	Submitter's comment	Response
	both islands.	
Vestas	Agreed. A single composite standard will likely result in increased compliance costs, and more importantly, excessive reactive power support in locations in the network that would provide limited benefit to system stability and economical return.	Noted.
Windflow	A composite standard is likely to result in increased compliance costs over the proposed alternative of separate standards for North and South Islands.	Noted.

Q5. Do you agree that the WGIP wind generation scenarios are appropriate for the NPV analysis?

Submitter	**Submitter's comment**	**Response**
Contact	Yes	Noted.
Genesis	Yes	Noted.
NZWEA	The WGIP scenarios were developed in order to test the impact of different levels of wind penetration on different aspects of power system performance. They were not developed as forecasts of potential wind energy development, which is what appears to have occurred here. While on the subject of the WGIP analysis, we also note that this analysis was undertaken at a time when most of the existing wind generation fleet used simple induction generators. Since that time all of the new build (for projects of 30 MW+) has used DFIG generators with additional hardware, full converter technology, or synchronous generators so will have a far superior ride through performance to what the WGIP analysis had assumed. The majority of NZ's existing wind fleet now has some fault ride-through capability.	The WGIP scenarios were used to test the economic impact of the proposed fault ride through standards under different levels of wind penetration – an approach consistent with the WGIP project itself. The proposed fault ride through standards defines the performance level required as opposed to leaving it to generating companies to decide the level of performance that ought to be provided.
Trustpower	Trustpower wishes to remind the Authority that the WGIP scenarios were developed for the purpose of testing various power system limits and that significant effort was taken to reinforce to those involved in the WGIP process that these scenarios were not to be considered as forecasts. It appears to Trustpower that the EA is now using these scenarios as a proxy forecast.	The WGIP scenarios were used to test the economic impact of the proposed fault ride through standards under different levels of wind penetration – an

Submitter	Submitter's comment	Response
	As mentioned in Trustpower's response to Question 3 above, the WGIP scenarios also assumed that all new wind generation installed during the next 10 years would consist of simple induction machines. This has proven not to be the case and to the best of our knowledge no significant installations of simple induction machines have taken place in New Zealand since the development of Tararua 2 in the mid 1990's. While not directly related to the wind generation scenarios, Trustpower notes that in paragraph 4.6.3 the EA is proposing to waive compliance costs for non-conforming synchronous generators. While Trustpower agrees with this for existing non-conforming synchronous generators and generating stations of less than 30MW it does not agree that new large non-conforming synchronous generation plants should be exempt from costs associated with their lack of compliance.	approach consistent with the WGIP project itself. The proposed fault ride through standards define the performance level required as opposed to leaving it to generating companies to decide the level of performance that ought to be provided. Trustpower's last comment may relate a misinterpretation of paragraph 4.6.3. It is not intended that synchronous generating plant be excused from costs associated with lack of compliance.
Windflow	Based on publicly available information, the 10-year wind generation development scenarios A, B and C appear to be appropriate for the NPV analysis.	Noted.

Q6. Do you agree with the Authority's input assumptions for the NPV calculations? If not, please provide alternative input values.

Submitter	Submitter's comment	Response
Contact	Purchasing of additional reserve to cover wind turbine risk is likely to put upward pressure on the market price. Addition exposure to dry and wet years should also be considered - so a P10 and P90 sensitivity could be used for FIR and SIR reserve prices to indicate a probable cost range (rather than relying on averages).	This would involve a much more complicated analysis. The NPV calculations show positive benefits without allowing for the additional benefits that would result from upward pressure on the market price of reserve.
Genesis	Genesis Energy believes the total installed wind turbine cost of $2.4 million per megawatt (MW) used in the calculations is a bit low and would recommend a figure closer to $3 million per MW. The other input assumptions for the net present value calculations appear reasonable.	The suggested $3 m/MW cost is closer to the current long run marginal cost of wind generation. The updated cost benefit analysis reflects this figure.
NZWEA	The NPV necessarily includes a number of averages and approximations that make it suitable only for a general consideration of the issue. For example the proposed 1.25% increase in turbine cost for ride through compliance is well within the margin of error in the range of turbine installed costs and will also be turbine and project dependent. The analysis also appears to be based on a scenario where the average wind penetration exceeds the largest contingent event (i.e. total NI wind generation exceeds 350 MW, or total SI wind generation exceeds 100 MW). This is unlikely	The analysis necessarily uses averages and approximations. Wind turbine costs are not publically available and the project dependent cost variations cannot be assessed of plant not yet built.

Submitter	Submitter’s comment	Response
	to be a credible scenario unless a new wind farm project is built with a generation capacity in excess of 350 MW, as the geographic distribution – and connection - of wind generation projects means that they will not all experience a fault at the same time. Under this distributed scenario the forecast increase in SIR and FIR costs would not occur until wind penetration reached a much greater level. (We also note that the high costs of SIR and FIR in 2008 will have resulted in “average” costs that are possibly higher than the long-term average that would be applicable over the period of the NPV calculation). Having requested and obtained a copy of the NPV calculation from the Authority we note that the analysis is more about whether there are benefits in applying the new standards today rather than at a future date when total wind penetration has increased, as opposed to whether there should be standards at all. An NPV analysis for the latter scenario would undoubtedly show that applying FRT standards will provide benefits (and this is the reason why all of the major new build has used technology with FRT capability). While we have these doubts about the veracity and application of the NPV calculation we still consider that it is appropriate for the consultation paper to conclude the FRT standards are necessary.	It is accepted that the analysis takes a conservative view of the reserve required to cover wind generation risk, but detailed system modelling would be required to produce more accurate results. It is not necessary to produce more accurate results given that the conservative approach produces a positive NPV. The NPV calculation tests whether there is a positive NPV for the proposed standards. This is the ‘latter scenario’ described in NZWEA’s comment. Sensitivity analysis was carried out on the assumed level of wind penetration in the next 20 years. The analysis noted that some delay in the introduction of fault ride through standards could be tolerated, but the

Submitter	Submitter's comment	Response
		period of any delay would be sensitive to any major wind farm developments.
Repower Australia Pty Ltd	Regarding the statement "NPV calculations use 1.25% for 2011, ramped down to 0% by 2020. The basis of this assumption is that compliance costs will decline over time as full scale converter technology becomes a standard feature of grid connected wind turbines" Manufacturing wind turbines with FRT/OVRT capabilities always results in an increase in the cost of wind turbines. The more severe the voltage drops the higher the cost for electrical protection equipment and drive train strength. FRT/OVRT costs do not depend on the variant of the electrical system and are therefore the same for full converter and DFIG systems.	Noted, but no alternative costing assumptions are suggested which could be used to improve the analysis.
Todd	Neutral. One of the inputs to the NPV analysis is instantaneous reserve prices and it is hard to predict where these will settle with the introduction of the national reserve market following the pending HVDC Pole 3 commissioning. While average price should go down through increased competition, the average quantity of reserve required is likely to increase with increased HVDC transfer capacity. It is hard to comment without seeing the NPV sensitivities to the input assumptions.	Noted.
Trustpower	While the figures of 437 MW and 61 MW for the installed base capacity of North and South Island's appears correct, the purpose and significance of these numbers is not clear to the reader. As discussed in Trustpower's response to	These figures are used in the calculation of wind generation capacity installed over the next

Submitter	Submitter's comment	Response
	Question 3 above it should be stressed that the majority of New Zealand's existing wind generating capacity does have GFRT capability. The reserve prices associated with the South Island are higher than Trustpower would expect on average – particularly the FIR. This is no doubt due to the inclusion of 2008. We feel it would be more appropriate to determine the average cost over a longer duration. The cost of providing GFRT capability by the provision of STATCOM type devices is not linear. That is, the cost per unit of STATCOM based GFRT capability generally reduces as the size of the plant increases. Therefore on small sites containing simple induction machines or DFIG's the cost is expected to be significantly higher than the 1.25% figure assumed in the analysis. A fixed + variable approach of say $2M + 1.25% of the project cost may be a more realistic way of representing the actual cost. Trustpower does also not necessarily agree that all wind turbines will contain full scale converter technology by 2020. It is not clear from the information provided what period, or duration, the NVP analysis was carried out over. While Trustpower and the EA may have differing views on the inputs to the NPV analysis we expect that the impact of these differing views is reasonably immaterial in the big picture. For example, when compared to the exorbitant costs associated with the procurement of frequency regulating reserve in New Zealand we consider the financial implications of GFRT to be reasonably minor.	10 years in accordance with the wind development scenarios. Average reserve costs were calculated over a four year period. The alternative costing assumption provided is also linear, but with an offset. The offset should more correctly be scaled down with the size of wind farm. Using the costs suggested by Trustpower, the NPV is positive provided wind penetration levels ultimately reach 1100 MW in the North Island and 700 MW in the South Island. The analysis was carried out over a 20 year period.

Submitter	Submitter's comment	Response
Vestas	The input values for compliance should be reviewed as they appear to simplify the scenarios considering that compliance will need to be evaluated on a case to case basis across the potential wind farm projects being assessed. There is no background provided on how the values have been determined if they have in fact been calculated based on aggregation of all the potential wind farms.	It is not possible to carry out a case by case analysis for future wind farm projects.
Windflow	The proposed standards are supported by a cost/benefit NPV analysis whose input assumptions include an optimistically low 2011 cost for compliance via power electronic frequency conversion (1.25% or $30,250 / MW, a key assumption from an undisclosed source), and the self-fulfilling assumption that this costly technology will have little net effect on ratepayers because its cost will disappear as it is universally adopted. The assumption that full frequency conversion will be universally adopted presumes that no alternative technology is available. This is simply untrue. NZ-made Windflow turbines drive synchronous generators which require neither power electronic frequency conversion for fault ride through compliance nor additional hardware for dynamic reactive power compensation. As presented, the NPV analysis shows a negligibly small 15-year NPV cost of $0.55 million. This cost blows out to $6.45 million if the self-serving assumption of disappearing costs is removed and the optimistic 1.25% pertains in each of the 10 years in which capacity is presumed to be installed. Should the actual cost of full frequency conversion be for example 5%, this NPV cost would blow out to $41.2 million. Windflow do not oppose adoption of the proposed standards. However, we advise against assuming that the cost of a costly and unnecessary technology	The NPV analysis compares the difference in cost between the proposed standards and the counterfactual (no standards). The assumption made in the analysis is that this difference in cost, as opposed to the actual cost of fault ride through technology, will fall to zero over a 10 year period as the technology is universally adopted.

Submitter	Submitter’s comment	Response
	will disappear should it be universally adopted.	

Q7. Do you agree that there is a moderate to high probability of scenario B wind penetration levels being reached in the next 10 years?

Submitter	Submitter's comment	Response
Contact	If unchanged, the current HVDC charging regime is likely to continue to dissuade some South Island generation projects, including grid connected wind farms. This will reduce the likelihood of scenario B emerging.	Noted.
Genesis	Genesis Energy believes there is a moderate (not high) probability of scenario B wind penetration levels being reached within the next ten years. However, this will be dependent on a multitude of factors such as demand growth, potential investment in the transmission grid to facilitate renewables, upgrades to the HVDC link, competing generation technologies and expected investment in peaking plant (to provide the firming ability to address variability in wind generation output). We believe Transpower is best placed to answer this question, given its modelling of the entire electricity system.	Noted.
Meridian	Yes.	Noted.
NZWEA	New generation build, of any type, will be influenced by a range of factors such as electricity demand growth. However, given that existing NI capacity will reach around 515 MW by the end of 2012 and the level of interest and activity in the wind energy sector at present we would be surprised if the 900 MW of NI wind considered in Scenario B was not achieved within the next 10 years. At the end of this year total SI wind will exceed 100 MW, so is also well on the way to achieving the 300 MW considered in Scenario B. Over 1,000 MW of potential wind projects also have or are seeking consent in the SI. However the	Noted.

Submitter	Submitter's comment	Response
	potential for the larger scale development that would contribute the most to achieving this target is affected by the current HVDC pricing regime.	
Trustpower	In the North Island, yes. Particularly given that approximately 50% of that figure is already installed in the North Island and a number of other projects are either committed or close to being committed. In the South Island we are unsure. While a number of good sites have been consented the economics of developing large scale sites in the South Island is presently hampered by the current HVDC pricing methodology.	Noted.
Vestas	Possibly, but this would depend on a number of factors including gas prices, carbon prices, and the outcome of the EA's consideration of measures for HVDC link pricing.	Noted.
Windflow	There is a moderate to high probability of WGIP scenario B being reached in the next 10 years.	Noted.

Q8. Do you agree that there would be benefits in proceeding immediately with proposed fault ride through standards or should the effective date of the proposed standards be triggered at a future date by the level of wind generation penetration?

Submitter	Submitter's comment	Response
Contact	A target date of three years (or similar) should be used (rather than immediately) as it seems unreasonable to introduce such changes to projects already in development that have orders based on exiting code requirements. For example the Te Mihi geothermal project equipment procurement.	Noted.
Genesis	Genesis Energy does not believe the proposed fault ride through standards should be implemented until the impact of Pole 3 is incorporated into the analysis. Refer to comments in the cover letter.	The effect of the loss of Pole 3 (700 MW) was assessed on an n-1 basis, along with other credible contingencies.
MEUG	On balance we support the proposal to implement the Code amendment immediately. We agree with the logic in the consultation paper that trying to delay a Code amendment to an optimal date will introduce uncertainty to investors. In addition MEUG notes that the new wind farm investors affected will probably use latest technology turbines already compliant, and the investments will have scale advantages leading to nil or low incremental unit compliance costs because the Code amendment will not apply to new wind farms less than 30 MW	Noted.
Meridian	Yes. Meridian agrees that there would be benefits in proceeding immediately with the proposed fault ride through standards.	Noted.

Submitter	Submitter's comment	Response
NZWEA	Yes, we agree that it is appropriate to apply the new standards immediately. As discussed above, we are already seeing that most projects (including all of those above the 30 MW threshold) are installing technology with good ride through capabilities today. This proposed change should not then have a significant effect. What is considered to be "immediate" will need some consideration. There may be some projects that have made investment decisions already that are not yet "connected" (as per the text of the proposed code change) or may not be connected by the time the new standards are in place. Where these committed projects have a demonstrated fault ride through capability (which may also have been accepted by the system operator) it would appear to be inappropriate for this plant to now have to review and/or modify its design to meet the new standards.	Noted.
Repower Australia Pty Ltd	Repower recommends that the Electricity Authority proceeds with a lower FRT requirement similar to the German requirements in order to gather some experience on the behaviour of generators when riding through faults.	Noted.
Todd	No. We see there would be some benefit in immediately including the standards in the Code but with an effective date in the future (e.g. 5 years out, and in a similar vein to the routine asset testing requirements added under Part 8 of the Code). This would allow generation investors (wind especially) to phase in the requirements through the generation development process of concept design, primary plant evaluation and then procurement.	Noted.
Transpower	Yes, the proposed fault ride through standards should be effective immediately.	Noted.

Submitter	Submitter's comment	Response
Trustpower	As all wind farms greater than 30 MW constructed within New Zealand since the WGIP have contained GFRT capability Trustpower does not expect the introduction of the standards to materially affect wind farms. Further to this, from the study undertaken by the system operator it appears as if the deteriorating performance of the power system is being driven by other factors such as demand growth as opposed to new wind generation displacing existing synchronous generation. Trustpower therefore conditionally supports the introduction of the standards immediately. However, given the considerable duration between projects becoming "committed" and "connected" Trustpower would only support the immediate introduction if it applied to plants that were "committed" as opposed to "connected" at the time the standards were put in place and that if grandfathering provisions are put in place for all existing generation stations.	Noted.
Vestas	If adopted in their current form, the effective date of the proposed standards should be delayed to reflect the actual penetration of non-synchronous generators to ensure a near term economical benefited network system.	Noted.
Windflow	The proposed standards should take effect immediately rather than being triggered by a predetermined level of wind generation penetration, to avoid unnecessary uncertainty.	Noted.

Q9. Do you agree with the Authority's overall assessment that the proposal best meets the objective of the proposal?

Submitter	Submitter's comment	Response
Contact	No. The analysis does not include the HVDC with Pole 3 which is a significant omission. The reserve cost assumptions in the NPV calculation also need testing over a sensitivity range as suggested. Clarification on how generators prove their assets are compliant to the proposal is required under the Code section B.	The effect of the loss of Pole 3 (700 MW) was assessed on an n-1 basis, along with other credible contingencies.
Genesis	No. As noted in the cover letter, Genesis Energy recommends that this proposal should be delayed until the impact of Pole 3 on voltage stability can be assessed. We also believe there needs to be further analysis of the effects of the proposed fault ride through standards on plant protection schemes and voltage sensitive auxiliary equipment. For example, will sustained over-voltage cause saturation of plant transformers and cause the operation of differential protection relays.	The effect of the loss of Pole 3 (700 MW) was assessed on an n-1 basis, along with other credible contingencies.
Meridian	Meridian is satisfied that the proposal is in the interests of economic development of electricity supply.	Noted.
NZWEA	NZWEA generally agrees with the proposal. Some of our relevant comments have been provided above, but in general terms we agree with the proposal subject to: • Recognition that the need for the change is not being driven by the installation of simple induction generators with limited or no FRT capability increasing system risks and displacing other generation. The significant new wind projects being installed today all feature FRT	Noted. The intention is that the proposed standards apply to all

Submitter	Submitter's comment	Response
	capability and other factors such as demand growth are potentially creating greater system instability risks. • It should be clear that the new standards will apply to all new generation and not just those with non-synchronous generators (for example section 4.6.3 of the paper suggests that "…only non-synchronous generators…will face compliance costs"). Provision should be made for a "negotiated standard" to be applied where an alternative (but not more onerous) envelope is applied, where this can be demonstrated (i.e. via system studies) to provide equivalent or better system performance with equal or lesser cost. NZWEA understands that such provisions exist in the Australian NEM, for example.	new generation. This provision is already available through the dispensation process in part C of the Code.
Todd	Yes, subject to responses above and further comment below. The objective of the proposal is to maintain the long term security of the grid, the notion that demand will continue to be met under grid contingencies. Where cogeneration plant are installed to satisfy stringent security of supply requirements of on-site co-located load, the owners of such plant should, within reason and with reasonable conditions imposed, be able to access a dispensation against the fault ride through standards where compliance would otherwise jeopardise security of supply to that co-located load. We note the Paper infers that synchronous generators (these being the likely form for majority of cogeneration plant installed) should largely be able to meet the standards, however the load and generation interdependencies for cogeneration plant are very much localised and thereby more complex, requiring detailed assessment against the standards on a case-by-case basis.	This provision is available through the dispensation process in part C of the Code.

Submitter	Submitter’s comment	Response
Transpower	Yes	Noted.
Trustpower	No, not completely. As discussed in Trustpower’s response to the questions above, Trustpower supports the concept of GFRT standards. However, it does not believe the argument that the requirement is being driven by simple induction based wind generation displacing existing synchronous generation.	Noted.
Vestas	The proposed generic fault ride through envelopes as a standard requirement across the whole network will impose additional costs onto many projects using non-synchronous generators in locations where such demands for such a tight regulatory envelope may not be necessary. This proposal could result in additional levels of reactive power support without a clear and demonstrated need that it is required to maintain stability of supply at the specific location of the project.	The proposed standards are intended to be generic and not customised to geographical locations. The dispensation process is available if it can be shown that the proposed standards need not apply at a particular location.
Windflow	The assessment of the proposal’s costs is questionable, as discussed under Q6.	Noted.

Specific comments on the proposed Code amendment

8.20A Fault ride through

(1) Each **generator** must ensure that its **assets**, when connected, remain transiently stable and connected without tripping any **generating unit** within the no-trip envelope shown in Figure 1 or Figure 2 (as applicable) during a solid three-phase short circuit fault or any unbalanced short circuit fault on any part of the **grid** at voltages of 110 kV or 220 kV.

(2) A **generator** is not required to comply with subclause (1) if clearing the fault would effectively disconnect the **generating unit** from the **grid**.

(3) A **generating unit** may trip 3 seconds or more after initiation of a fault on the **grid**, as described in subclause (1), if this action is an intentional part of a special protection system.

Figure 8.1: North Island fault ride through envelope

Figure 8.2: South Island fault ride through envelope

Submitter	Submitter’s comment	Response
Meridian	8.20A(3): A generating unit may trip 3 seconds or more after initiation of a fault on the grid, as described in subclause (1), if this action is an intentional part of a special protection system." Meridian notes that, in some circumstances, SPSs are designed to avoid system instability which can develop rapidly following fault inception. In these cases it is usually preferable to trip generating units as soon as practically possible, often within 200ms, in order to avoid system instability. For example SPSs at Manapouri and White Hill power stations are designed to trip units within 200ms in order to avoid instability and potential system collapse. Meridian	Noted and clause 8.20A(3) amended accordingly.

Submitter	Submitter's comment	Response
	suggests that a sentence be added that reads "A generating unit may trip immediately after initiation of a fault if this action is an intentional part of a SPS which has been designed in cooperation with the system operator or Distribution Network Operator in order to comply with system operator or Distribution Network Operator performance obligations."	
Philip Wong Too	8.20A (1). My interpretation is that the no-trip envelope refers to voltages on the 110 kV and 220 kV grid, not the grid injection point (if this is not at 110 or 220 kV), nor the generator terminals. This could be potentially made clearer by changing the y axis labels from "Grid Voltage" to "110 or 220 kV Grid Voltage".	Agreed.
Philip Wong Too	8.20A (1) "remain transiently stable". My understanding is that there are certain parts of the grid where there are limits on power transfers due to transient stability, and that this is due largely to the characteristics of the transmission system, rather than deficiencies in the generation units involved. A possible interpretation is that the generation assets involved would not be compliant under the proposed code. Care may need to be taken to ensure that the proposed changes to the Code does not have unintended consequences in areas such as where flows on the transmission system are limited by transient stability.	Noted.
Repower	The FRT profiles for the North and South islands should be changed such that voltage returns to values above 0.8 p.u. at 3 seconds after the disturbance. Assumptions in simulation studies and safety margins should be re-assessed. This part of the voltage profile is more stringent than any other grid codes and would increase the cost for manufacturers in providing FRT.	International comparisons indicate that the proposed fault rise through standards are similar to those contained in a number of grid codes.

Submitter	Submitter's comment	Response
	The investigation by Transpower states that all worst case scenarios were considered and an average was taken and then a 5% safety factor was added. In the Transpower report, only 2 simulations can be found where the voltage after the disturbance was at 0.80 p.u. or less after 3 seconds. The 0.75 p.u. voltage recovery at 3 seconds is not clearly justified in the report. It is unclear whether the simulations were done with the assumption that wind turbines provided reactive current support. If this is the case then post disturbance, the voltage should return to nominal more quickly than the simulations suggest.	The studies were completed with the assumption that wind turbines provide reactive current support. It is likely that some existing turbine absorb rather than provide reactive current support.
Repower	The vertical axis of the FRT profiles should be defined as "line to line voltage of the faulted lines" instead of a generic "voltage". The exclusion of requirements for asymmetrical faults are a common omission in grid codes because studies are performed with RMS models. These codes often refer to a generic "voltage" or a "positive sequence voltage". Grid operators that have explicitly taken asymmetrical faults into account use wording to refer to the "lowest line to line voltage". An example of this is the Germany Grid German Medium Voltage Directive 2008.	Agreed.
Repower	Over voltage requirements should be limited to below 1.2 p.u. for 100 ms and below 1.15 p.u. for 1000 ms. Assumptions in simulation studies and safety margins should be re-assessed. Standard medium voltage components like switchgear, cables and transformers are rated for these over voltages, forcing wind farms developers to use a higher class of components (e.g. 30kV components on 20kV wind farm grids) or operate the equipment below rated voltage. Both would increase the cost of	The over voltage requirements were developed from actual system studies, rather than from a theoretical approach.

Submitter	Submitter's comment	Response
	wind power simply because a few percent of over voltage requirements could not be met.	
Todd	Subclause 8.20A(1): In the first sentence after the words "Each generator" add the text *", other than generators who are owners of excluded generating stations,"*	This exclusion is covered in clause 8.20D(3).
Todd	Subclause 8.20A(3): There are circumstances where Special Protection Systems (SPS) or other ancillary service contracts will require the tripping of a generation unit well within the 3 second window proposed under this sub-clause. Take for example existing generator provision of over-frequency reserve whereby the generation unit is required to trip instantaneously when the over-frequency threshold has been exceeded – it would be non-compliant with the subclause proposed by the Authority. We would suggest the proposed sub-clause be replaced with *"A generation unit need not comply with subclause (1) if this action is an intentional part of a special protection system or ancillary service product"*, or add this suggested text as further subclause under 8.20A(2).	Noted and clause 8.20A(3) amended accordingly.

8.20B Reactive current and active power output

(1) Each **generator** must ensure that each of its **generating units** generates maximum reactive current without exceeding the **generating unit's** transient rating limit during the period of a fault on the **grid** as described in clause 8.20A(1).

(2) Each **generator** must ensure that each of its **generating units,** relative to pre-fault **active power** output, provides **active power** output at least in proportion to the retained balanced voltage at the **grid injection point** following clearance of a fault on the **grid** as described in clause 8.20A(1).

(3) Subclause (2) does not apply to a **wind generating station** if there has been a reduction in the intermittent wind power source during the time range in Figure 1 or Figure 2 as applicable.

Submitter	Submitter's comment	Response
Genesis	Genesis Energy notes that it will not be possible for every generator to meet the requirements for maximum reactive current that are proposed in the draft Code amendments. The amount of reactive support a generator can provide depends on where the transformers are "tapped" at the time of the fault and it is not possible to change the tapping of a transformer within the timeframes proposed. The proposed Code change specifies a timeframe of five (sic, actually 0.5) seconds for over-voltage situations and three seconds for under voltage situation. However, it typically takes longer than this for a transformer's tapping range to be adjusted. We recommend that the proposed Code be amended to require generators to provide as much reactive support as possible during the period.	The maximum reactive current that a generating unit can generate should not be affected by the unit transformer tap setting. Genesis has assumed that maximum current injection into the grid is required, rather than maximum unit output.
Meridian	8.20B(1): "Each generator must ensure that each of its generating units generates maximum reactive current ....". The reactive power response of a unit is generally controlled by an Automatic Voltage Regulator with a closed loop (feedback loop) voltage control algorithm that regulates the reactive power output based on the measured voltage response. An open loop response (feed forward) as suggested in 8.20B(1) may lead to power system instability, and/or poor power quality during post-fault recovery. Reactive power response that is	This clause covers performance during a fault. An automatic voltage regulator would have minimal effect within this timeframe.

Submitter	Submitter's comment	Response
	proportional to the system voltage level may be better than full reactive power output during the fault. Meridian recommends that the Authority carefully reconsider this clause.	
Philip Wong Too	8.20B (2). This clause implies a perfectly linear and instantaneous response between the balanced voltage level and the active power contribution of the machine. Very few generators (wind or otherwise) are likely to have such a perfect response, with damped oscillations of active power output being much more typical in my experience. Further, in order to control drive train transients in certain wind turbine configurations, it may be necessary to ramp up power output in a controlled manner. This suggests to me that either dispensations to this clause will need to be made on a very pragmatic basis, or alternatively that this clause is reworded. A possible reword could be along the lines of "within X seconds of fault clearance the active power injection shall recover to Y% of the pre fault levels."	No significant deviation of output is expected to occur following a fault. A more prescriptive recovery, as proposed, could not be made given the differences in inherent parameters of generating units connected to the grid.
Repower	Please alter "following clearance of a fault" in 8.20B (2) to "after voltage has returned to 90% of nominal" for the reasons that: (a) it could be misunderstood that active power in-feed is necessary from 100 ms onwards (b) feeding in Active Power is impossible at very low voltages.	It is intended that active power in-feed is required immediately after fault clearance.
Repower	Reactive Current injection during FRT should be limited to voltages above 0.4 p.u. for the reasons that: (a) Feeding in reactive power before grid protection has cleared the fault	Reactive current injection is required to ensure that protection operates correctly to clear a fault, and subsequently

Submitter	Submitter's comment	Response
	(t<140ms) does not support the grid voltage. The only thing needed during this time is a short circuit contribution. (b) DFIG provide a short circuit current irrespective of a controlled reactive current injection (c) Allowing Generators not to provide reactive current support during low voltages allows for a more cost effective design. (d) The German transmission code and the draft European network code by ENTSO-E already take this into account and only ask for reactive current support above 0.45 p.u. and 0.40 p.u. of residual voltage respectively.	to support voltage recovery.

8.20C Use of additional equipment

A **wind generating station** may meet the requirements of clause 8.20A by—

(a) the performance of the **generating units**; or

(b) installing additional equipment within the **wind generating station**; or

(c) a combination of **generating unit** performance and additional equipment.

Submitter	Submitter's comment	Response
Trustpower	Clause 8.20C – Trustpower believes that this mechanism should be available to all generating stations as opposed to only wind generating stations as drafted. Recommendation - remove "wind". Clause 8.20C (b) - Like above, Trustpower believes that this mechanism should	Agreed.

Submitter	Submitter's comment	Response
	be available to all generating stations as opposed to only wind generating stations as drafted. Recommendation - remove "wind".	

8.20D Application

(1) A **generating unit** is not required to comply with clauses 8.20A and 8.20B for its remaining life if,—

(a) on the date on which this clause comes into effect, the **generating unit** is connected; or

(b) the **generating unit** has been connected prior to the date on which this clause comes into effect.

(2) Despite subclause (1), if a **generating unit** described in subclause (1)—

(a) at any time after the date on which this clause comes into effect, complies with clauses 8.20A and 8.20B, it must comply with clauses 8.20A and 8.20B for the remaining life of the **generating unit**:

(b) is subsequently replaced, the replacement **generating unit** must comply with clauses 8.20A and 8.20B.

(3) Clauses 8.20A and 8.20C do not apply to—

(a) a **wind generating station** when it operates at less than 5% of rated **MW**:

(b) a **generating unit** at an **excluded generating station**.

Submitter	Submitter's comment	Response
Philip Wong Too	I support the exclusion of generation stations of less than 30 MW.	Noted.

Submitter	Submitter’s comment	Response
Philip Wong Too	8.20D (2). "replacement generating unit". I would urge care in the implementation of this clause. While I support the intention to enforce fault ride through where a generator is replacing its generation units with improved units (say repowering a wind farm with new wind turbines), I do not consider this should apply where a generating unit is being replaced on a like for like basis. For example, where a single wind turbine requires becomes unserviceable, the wind farm owner should be able to replace the turbine on a like for like basis. Preventing this would probably preclude turbine replacement in many circumstances as wind turbines of that model may simply not be available with fault ride through capability and installing equipment at the substation is likely to be prohibitively expensive.	The intention is that any replacement units are required to be compliant. It is noted that no generating companies have expressed a similar concern.
Trustpower	Clause 8.20D(1)(b) – Rearrange the clause to allow for units that are “committed for construction” as opposed to “connected” prior to the date in which the clause comes into effect. Recommendation – substitute “connected” with “committed for construction”. Clause 8.20D(3) – Add “, 8.20B” after “8.20A”	Agreed.

Appendix F System operator's supplementary revision report

Generator Fault Ride Through (FRT) Investigation

Derek Carroll

SYSTEM OPERATOR

TRANSPOWER

Keeping the energy flowing

Version	Date	Change
1	20/7/11	Draft for internal review
2	9/9/11	Updated after initial GO feedback
3	19/9/11	Draft and after final feedback
4	28/10/11	Final - Updated after EA feedback
5	30/11/11	Updated for external use
6	1/2/13	Updated with alternative criteria
7	16/10/13	Updated to focus on Voltage Ratio Criteria, proposed Absolute Voltage limits.
8	11/02/14	Updated to include TOV beyond the influence of the HVDC terminals.

	Position	Date
Prepared By:	Derek Carroll	11/02/2014
Reviewed By:	Mohamed Zavahir	12/02/2014

Executive Summary

Based on submissions received on [1] and the completed HVDC upgrade, the System Operator has revised the Temporary Over-voltage (TOV) Fault Ride Through (FRT) requirements for the HVDC terminals on the North and South Island power systems. This revision consists of updated assumptions and studies to consider the loss of the HVDC bipole.

Beyond the influence of the loss of the HVDC bipole the impact of load response to a transient fault on the power system is considered.

During low Wellington load conditions the permanent loss of the bipole during HVDC north transfer level of 1200 MW could cause a significant TOV in either island due to the increased amount of reactive load removed from the system.

The Transpower HVDC TOV criteria have been considered in the analysis and have been used to develop the proposed TOV FRT requirements. Based on these requirements and the revised assumptions, it is recommended that the TOV FRT requirement in Figure A below be applied at the transmission High Voltage (HV) busses at Haywards for the North Island HVDC terminal and at Benmore for the South Island HVDC terminal. Note that these FRT performance requirements are based on the ratio of post disturbance to pre disturbance voltage at transmission HV level. The temporary overvoltage withstand ratings of any connected asset needs to be greater than this performance limit to ensure safe operation of the assets.

At transmission HV busses other than the HVDC terminals the TOV resulting from the permanent loss of the HVDC bipole will reduce as electrical distance from the HVDC terminals is increased until the TOV expected due to motor load tripping during an earth fault sets the TOV FRT envelope shown in Figure B.

Busses electrically close to the HVDC terminals will experience a TOV lower than that set by the HVDC Bipole block and higher than that set by the voltage recovery following motor load tripping during a fault.

The TOV expected at those busses can be determined from power system analysis using a time-domain simulation tool and incorporating a set of study assumptions to ensure the worst possible TOV is simulated.

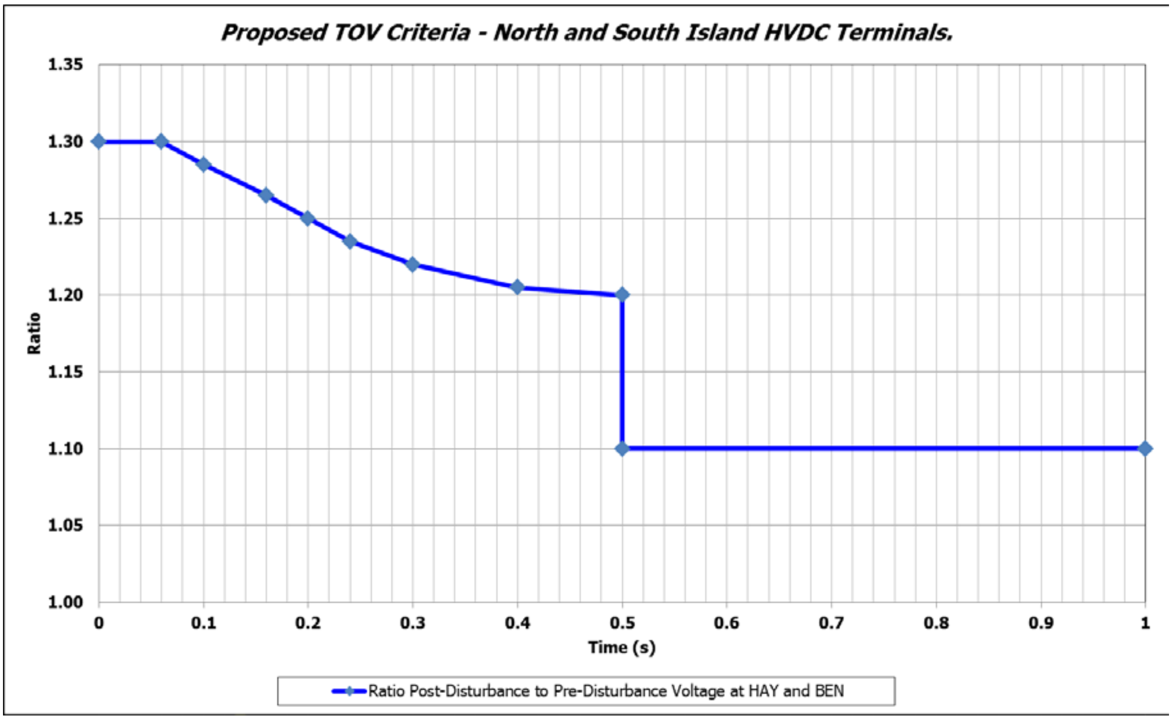


Figure A: Proposed TOV FRT envelope at HAY and BEN

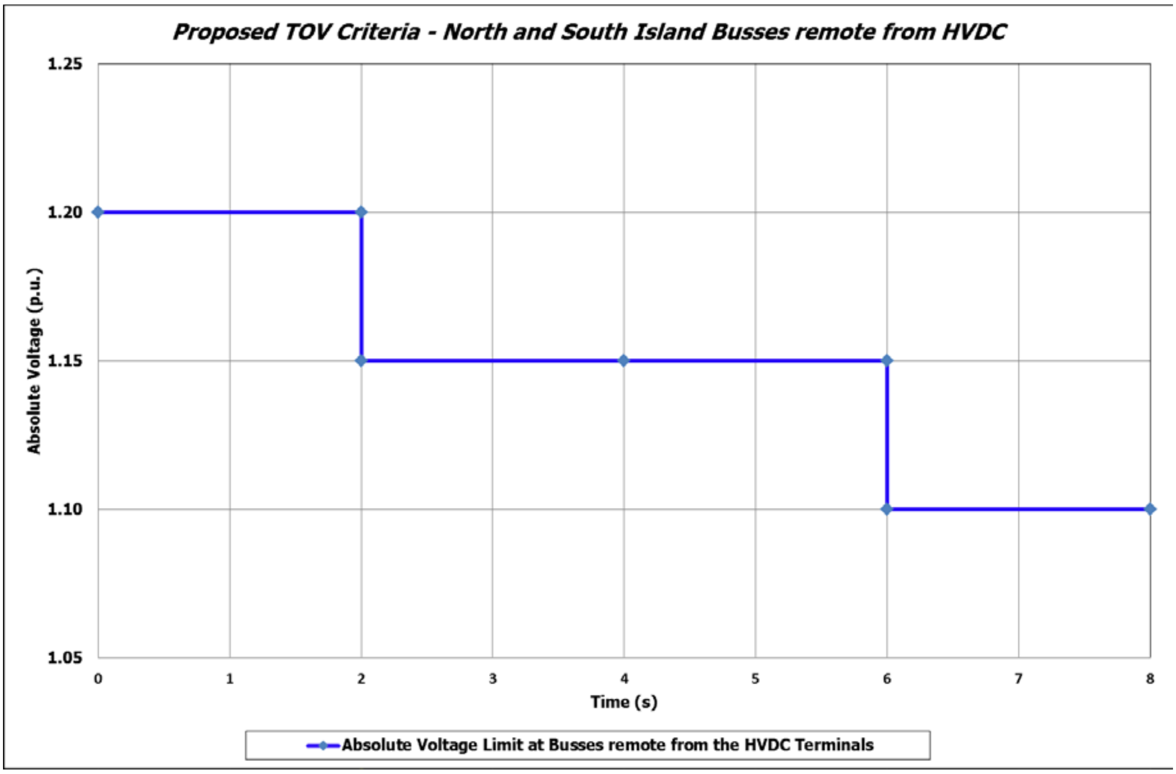


Figure B: Proposed TOV FRT envelope at busses remote from HVDC terminals.

Table of Contents

1 Introduction

Based on submissions received on Consultation Paper, Generator Fault Ride Through, Electricity Authority, December 2010 [1] the System Operator has revised the Temporary Over-voltage (TOV) Fault Ride Through (FRT) envelopes for the North and South Island.

The submissions referred to are the omission of the Pole 3 project (now commissioned), its impact on TOV system performance, and the events associated with the introduction of Pole 3.

Revised assumptions around TOV system performance and the results from the updated analysis are included in this report and should be read in conjunction with Generator Fault Ride Through (FRT) Investigation Stage 2, System Operator, 4 May 2010 [2].

2 Assumptions

The underlying assumptions remain the same as in the [2], with the exception of the committed upgrades and the credible contingencies considered in the TOV analysis.

2.1 Committed Upgrades

The original analysis in [2] was commenced in 2009 and assumed committed upgrades based on the 2008 System Security Forecast (SSF) which did not include the HVDC Pole 3 project. Based on submissions received commenting on the exclusion of Pole 3 and the need for this to be considered in the analysis, the revised analysis assumes Stage 2 of the HVDC Pole 3 project. Stage 2 has a maximum transfer capacity of 1200 MW.

2.2 Credible Contingencies

The contingencies in the original analysis were chosen based on the effect that they have on a regional and sub-regional transmission level under n-1 (loss of a single power system element). It was shown in [2] that the loss of an HVDC pole was the critical contingency for all regions with respect to system TOV. As mentioned in section 2.1, submissions from participants have prompted the inclusion of Pole 3 in the analysis and it is now prudent to consider the loss of the HVDC bipole due to its impact on the system.

Certain types of system faults can, and have in the past, cause interruption to the HVDC bipole transfer. If the fault is cleared and voltage recovery is sufficient to restart the HVDC, then this event, which can be caused by a loss of an AC transmission circuit at Haywards (HAY) or Benmore (BEN), is considered a temporary loss. If a bipole block event occurs, which can be predominantly caused by a DC fault or control failure or severely weakened AC system, then this results in a permanent loss of the HVDC.

It is critical that existing and proposed generation remain connected for this event in order to manage system stability. There may be insufficient under-frequency reserves to meet the limits specified in the code if additional non-compliant generation is added to the bipole risk. This may also result in a limitation on the HVDC transfer and/or rescheduling of this generation if there are insufficient reserves available.

2.3 Existing TOV Criteria

Transpower has existing TOV criteria that were used for the design of Pole 2 and Pole 3. These criteria are specified as a ratio of post-disturbance to pre-disturbance 220 kV bus voltages at HAY (limited to a maximum of 1.45 p.u. absolute) or BEN (limited to a maximum of 1.3 p.u. absolute). These design criteria are applied to all stages of the project. Full details of the HVDC criteria are given in the Appendix in section 6. These criteria are further considered in section 3.1 and are shown in Figure 1 below.

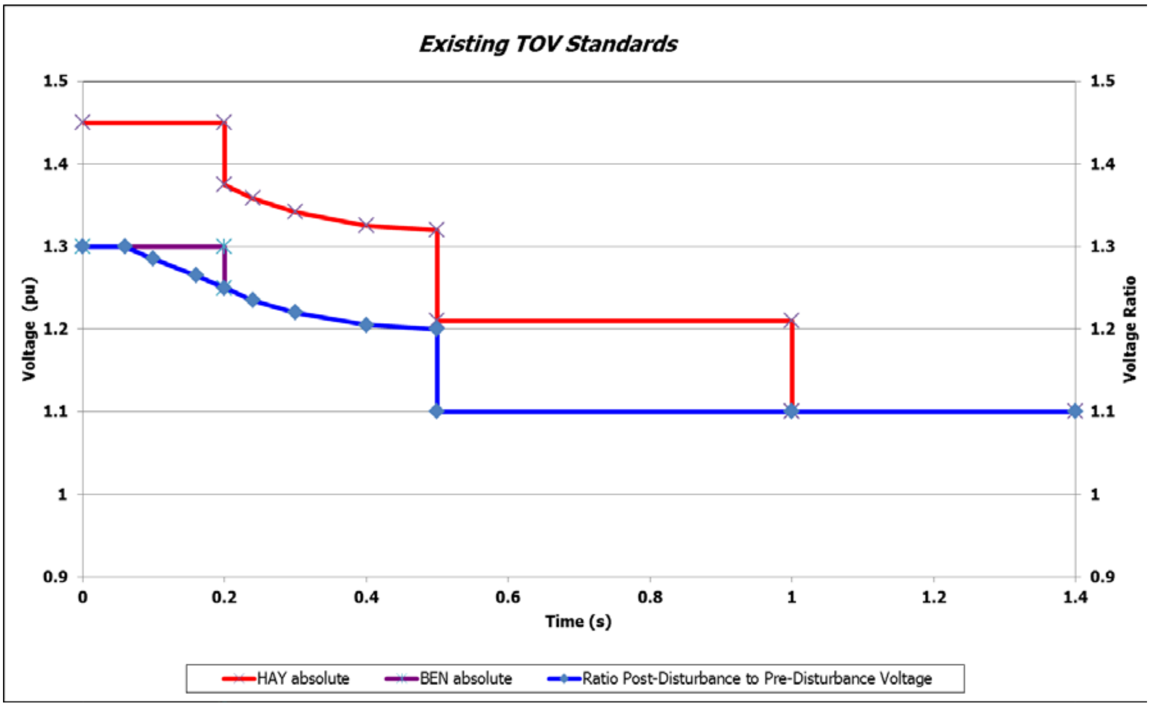


Figure 1: Existing TOV Criteria

2.4 Load Modelling

The revised study assumes the same composite load model as the original analysis.

As described in [2] composite load models were used at each GXP in the dynamic studies carried out. The proportion of each component of the composite model was determined from survey data collected for the grid owner.

2.5 Study Scenarios

As the maximum absolute voltage limit set in the HVDC criteria is an onerous requirement to apply to the entire system, analysis of a number of scenarios has been completed to determine suitable requirements for various regions within the system based on electrical proximity to the HVDC stations.

The HVDC transfer scenarios focussed mainly on north flow conditions. HVDC south flow scenarios have been considered but not analysed as the TOV is an issue for transfers of greater than 850 MW. The availability of under or over frequency reserves, or voltage stability limits are expected to constraint HVDC south transfers below that level.

2.5.1 Loss of the HVDC

To illustrate the extent of the TOV, both the temporary and permanent bipole loss scenarios are modelled against the existing HVDC criteria. The analysis assumes:

- All transmission equipment in-service.
  - The study does not investigate the impact of planned or unplanned transmission plant outages.
- Lowest forecast Wellington demand (consisting of GZ8, i.e. all substations between BPE and HAY) and corresponding system demand.
  - The impact of a permanent loss of the HVDC bipole is most pronounced during low demand periods.
- All reactive equipment for bipole operation and maximum transfer capability is available and in-service at HAY and BEN.

- The impact of a permanent loss of the HVDC bipole is due in a large part, and most pronounced, when all required reactive support and filtering for the HVDC bipole is in service.

- HVDC north transfer approximately 1200MW, sufficient to cause a TOV that touches the envelope at the HVDC terminal in the island power system being studied.
  - With the TOV at HAY or BEN set to maximum allowed the worst case TOV at busses under the influence of the permanent loss of the HVDC bipole can be determined.
- All generation between BPE and HAY out of service and disconnected. Generation in the Waitaki hydro system around BEN minimised as far as possible while maintaining acceptable voltage support and reserve provision.
  - With the generation in the areas of the grid under the influence of the permanent loss of the HVDC bipole the worst case TOV at busses in those areas can be determined.

2.5.1.1 Temporary Loss

The analysis assumes a fault clearance time at BEN (BEN-OHC 220 kV circuit) or HAY (HAY-LTN 220 kV circuit) of 120 ms and a further 200 ms for the HVDC to ramp back up to pre-fault transfer. The restart time is within the time for the Reactive Power Controller (RPC) to switch out/in reactive plant at HAY and BEN.

2.5.1.2 Permanent Loss

The permanent bipole loss results in the RPC switching out/in reactive plant at HAY and BEN to manage system voltage levels. The HVDC bipole is tripped and the actual tripping sequences are applied to reactive plant.

2.5.2 Loss of motor load following a fault.

The behaviour of the motor load component of the composite models to credible contingencies was examined to determine the potential worst case TOV that may be experienced on the power system.

The assumption used in [2] that up to 50% of the group 1 motor load component could be removed during a fault was considered. The analysis assumed summer peak demand and examined the impact of a close-in, 3 phase, zero impedance fault resulting in the loss of a single network element. The fault which resulted in the worst TOV was found to be on the HLY-OTA 2 220kV circuit. Following this fault bus voltages in the Auckland region were shown to experience a TOV during the recovery phase.

Static reactive equipment in the region affected by the fault was utilised as required to ensure that any dynamic reactive equipment was maintained at or around 0MVAr output prior to the disturbance.

Automatic switching of reactive equipment in response to the TOV was modelled where available.

3 Analysis and Results

As expected, studies indicate the bipole loss with HVDC north transfer level of 1200 MW will result in a significant TOV in either island due to the increased amount of reactive load removed from the system (around 50% of the MW capacity). The following figures show system performance against the HVDC criteria for relevant 220 kV busses for the scenarios outlined in sections 2.5.1.1 and 2.5.1.2.

3.1 Loss of the HVDC Bipole

As mentioned in section 2.3, the HVDC criteria is a voltage ratio (1.3 x) based on the pre and post-disturbance voltage at HAY and BEN with the post-disturbance voltage capped at 1.45 and 1.30 p.u. absolute respectively. The pre-disturbance voltages assumed in this study at HAY and BEN are 1.04 and 0.99 p.u. and therefore with reference to section 6, the maximum permissible TOV in this study was 1.352 and 1.288 p.u. at fault inception respectively as the initial rise must be limited to the ratio of 1.3 times the pre-disturbance voltages.

The overvoltage curves shown below are illustrative of the TOV that can be experienced at HAY and BEN and indicate how the TOV must fit within the ratio limit. These curves were not used to create the TOV ratio envelope.

3.1.1 Temporary Loss

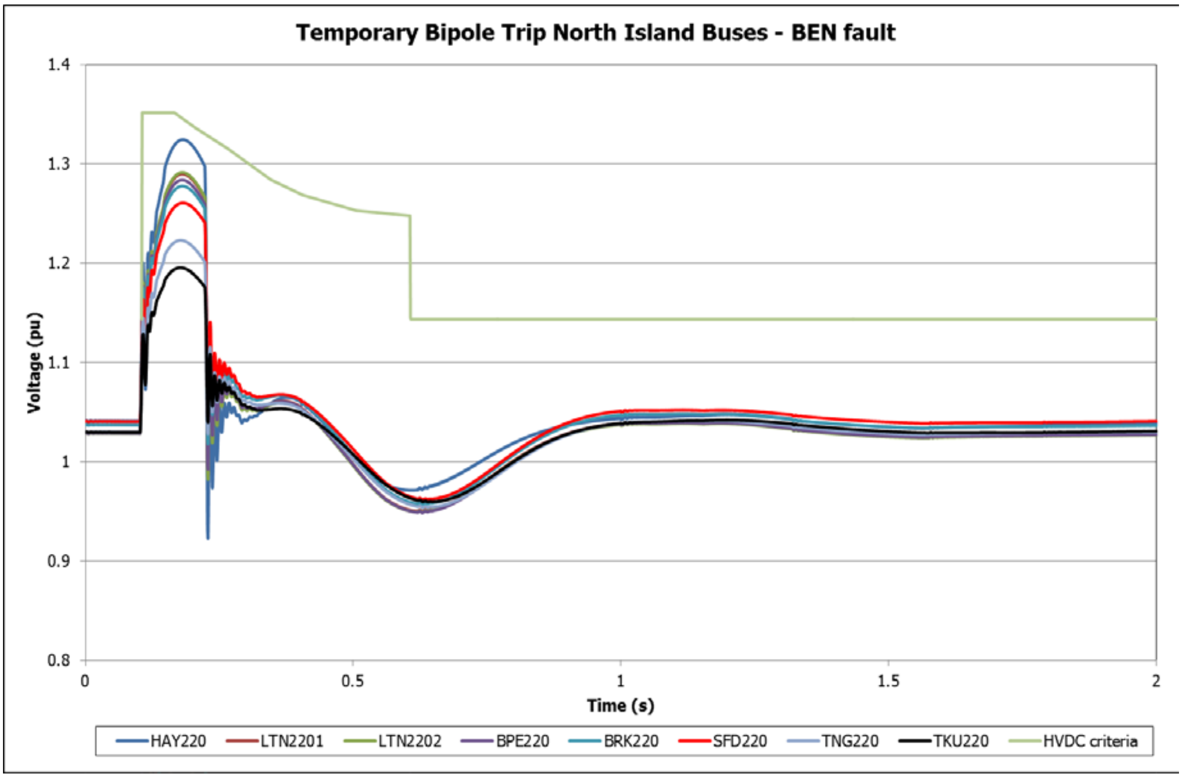


Figure 2: Temporary Bipole Trip - North Island Busses

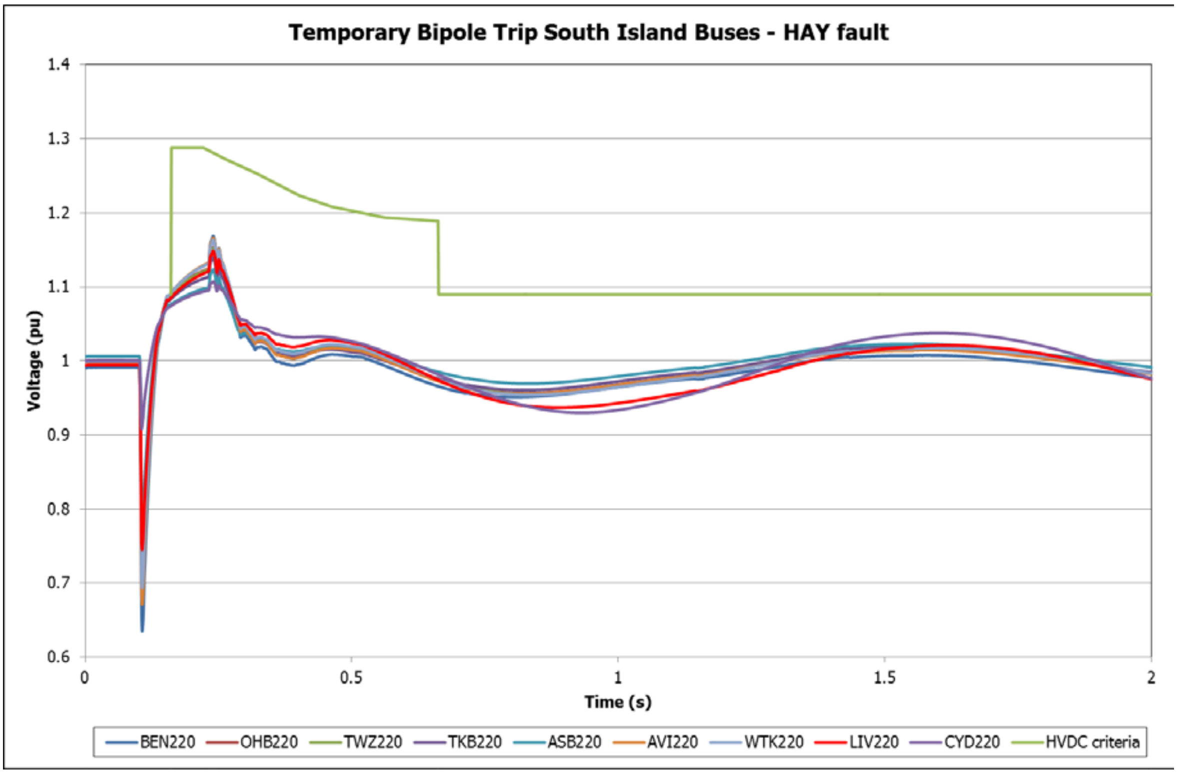


Figure 3: Temporary Bipole Trip - South Island Busses

As can be seen from Figures 2 and 3 the HAY and BEN TOV are within the HVDC TOV criteria. The HAY peak is 1.32 p.u. and the BEN peak is 1.17 p.u. which is less than the limits mentioned in section 2.3 and both busses remain within the statutory requirement of 1.1 p.u.

3.1.2 Permanent Loss

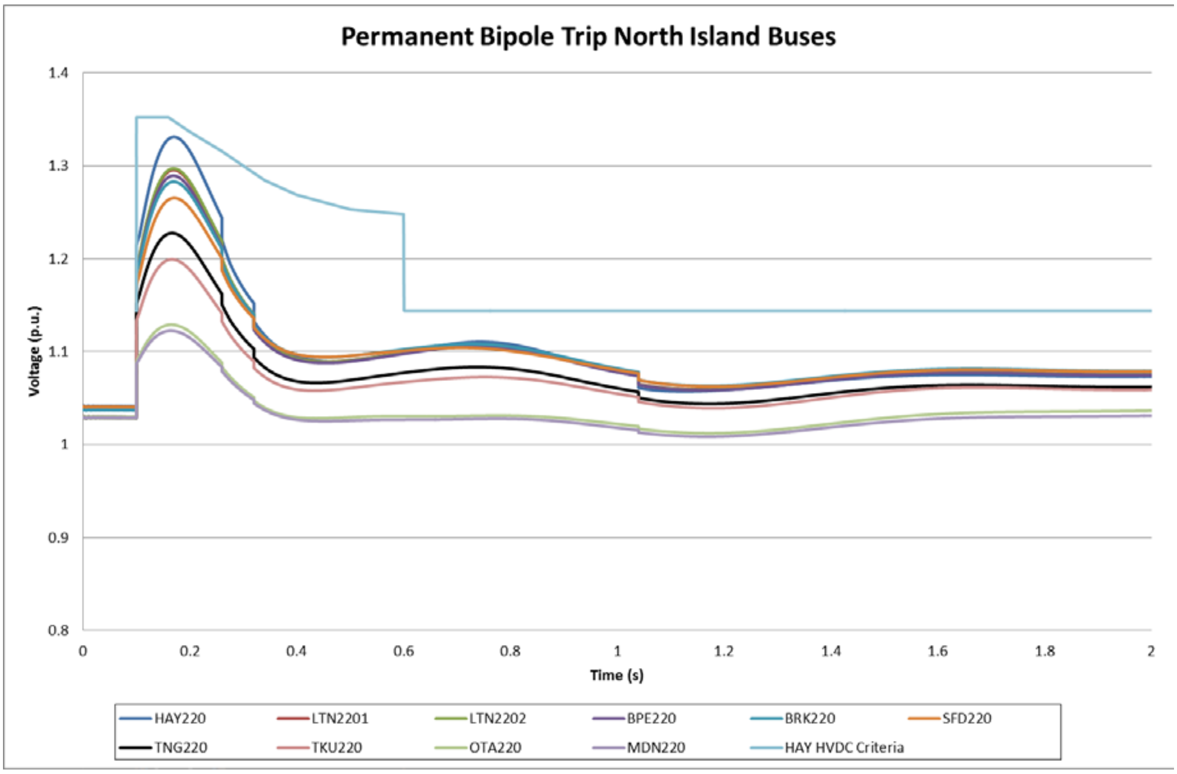


Figure 4: Permanent Bipole Trip - North Island Busses

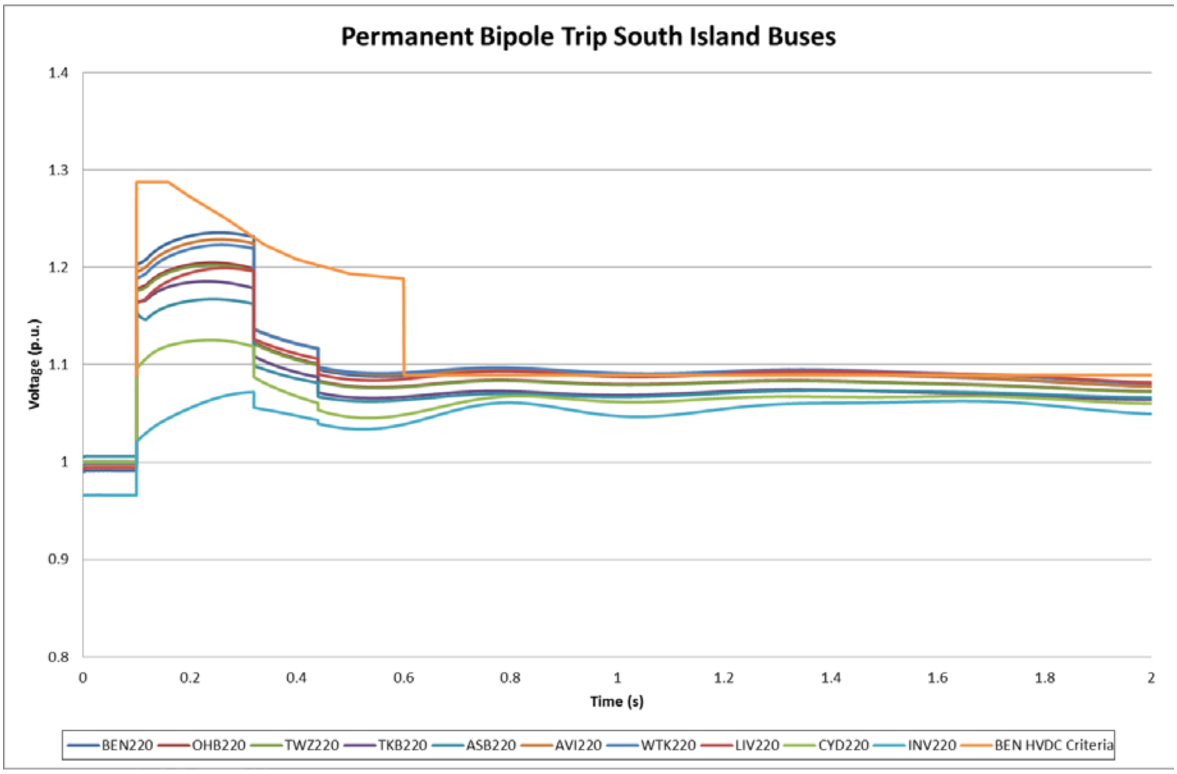


Figure 5: Permanent Bipole Trip - South Island Busses.

As can be seen from Figures 4 and 5 the HAY TOV is within the HVDC TOV criteria whilst the BEN TOV is marginally above the criteria at the 0.6 second point (but is still within 1.1 p.u. absolute). The HAY peak is 1.33 p.u. and the BEN peak is 1.23 p.u. which is less than the limits mentioned in sections 2.3 and 3.1.1, and both busses are within the statutory requirement of 1.1 p.u. after 1 second.

3.2 Loss of motor load.

As described in [2] and further mentioned in 2.5.2 above, the loss of motor load following a fault can result in a TOV at busses in the region surrounding the location of the fault. Studies carried out in the Auckland regions were used to determine the magnitude of the TOV and these results were used to determine an appropriate envelope for a TOV FRT requirement.

3.2.1 <u>Fault resulting in a loss of motor load.</u>

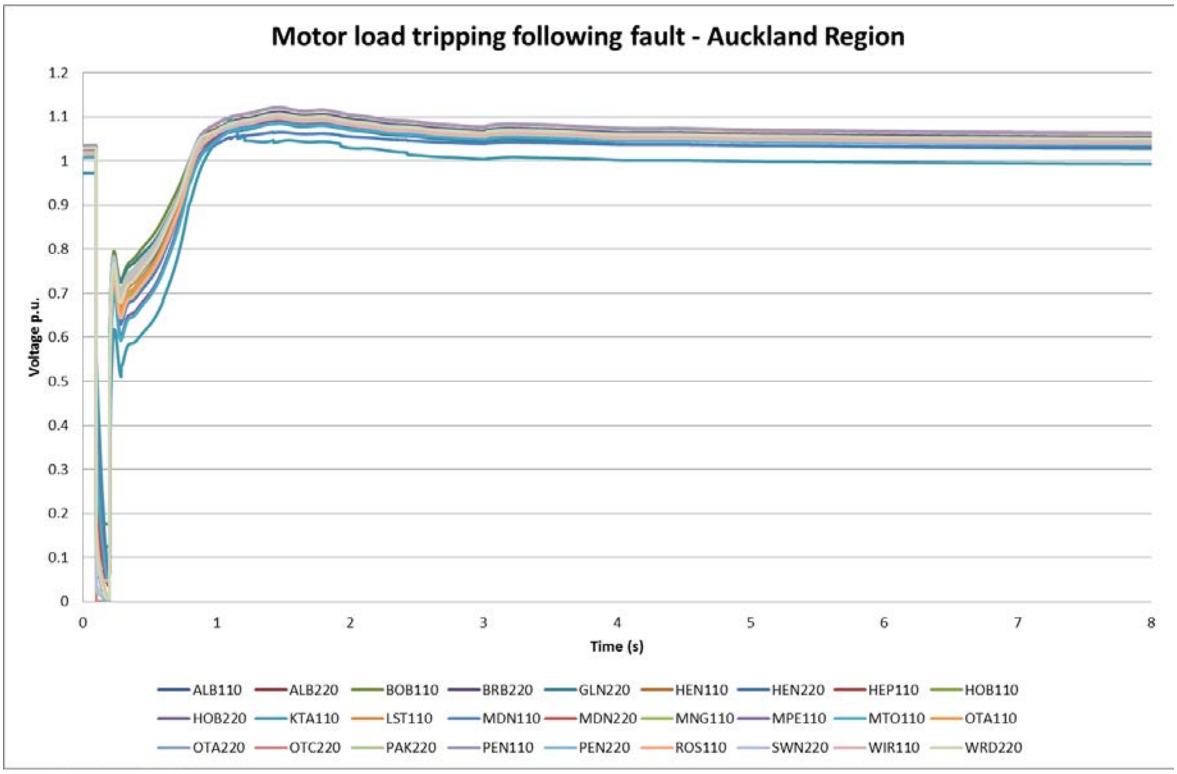


Figure 6: Three phase fault close to OTA resulting in motor load tripping.

Figure 6 shows the bus voltages in substations rising above 1.1 p.u. in the recovery phase after a close-in, three phase, zero impedance fault near OTA 220kV bus (HLY-OTA 2 220kV). Automatic capacitor switching at KTA in response to the overvoltage can be seen.

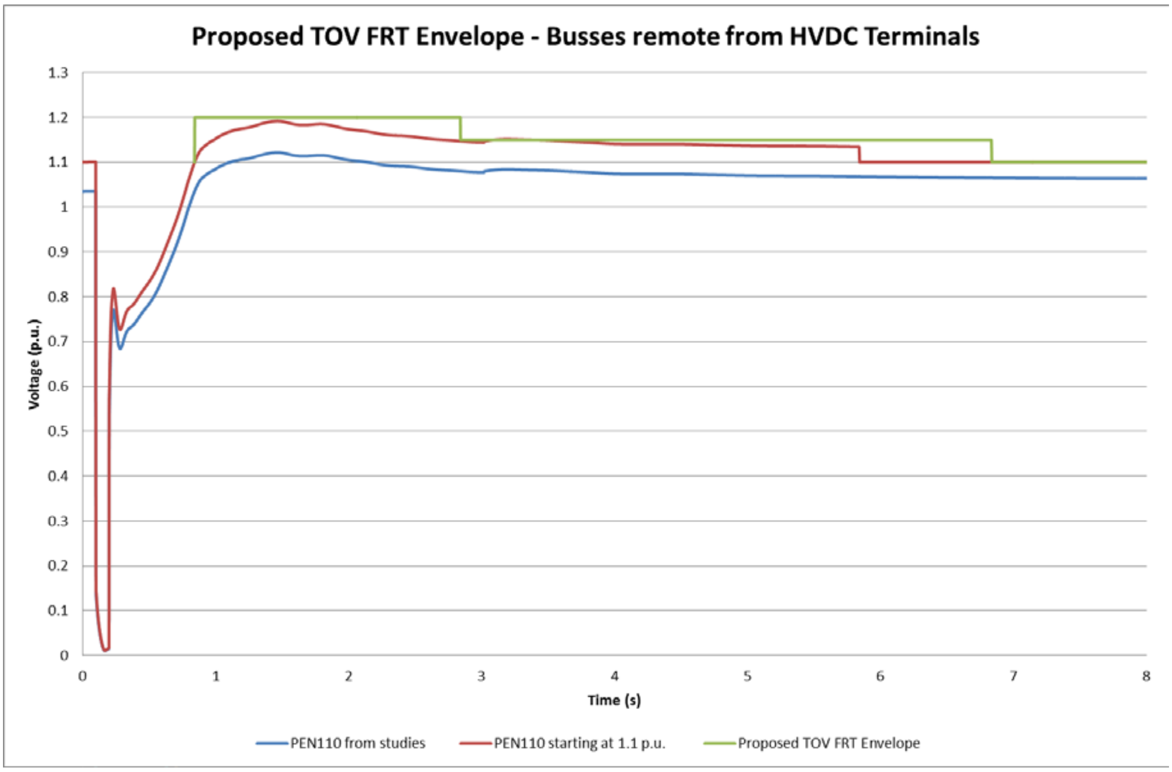


Figure 7: Proposed TOV FRT envelope based on worst case studies.

Figure 7 shows the expected worst case TOV from the studies carried out, at PEN 110kV bus, and the TOV expected with the starting voltage at PEN scaled up to 1.1 p.u. which is the maximum steady state voltage allowed under the Electricity Industry Participants Code (the Code).

The voltage is seen to remain above the maximum allowed in the Code until approximately 5 seconds after the TOV started when automatic capacitor switching is expected to return the steady state voltage below Code limits.

Using the results of this study a TOV FRT envelope was developed. The envelope is specified as an absolute voltage limit for a specified duration.

Above 1.1 p.u. absolute voltage, the TOV may increase to a limit determined as 1.2 p.u. absolute. After 2 seconds the bus voltage must return to below 1.15 p.u. absolute. After another 4 seconds the voltage must return below the steady state limit set in the Code, i.e. 1.1 p.u.

3.3 Summary

The worst case TOV is created by the permanent loss of the HVDC bipole. The TOV will increase for the planned HVDC capability of 1400MW in the future, and additional dynamic reactive support will be required to maintain voltages within the TOV limits.

The absolute voltage TOV limit envelopes of the HVDC TOV criteria are based on voltage withstand levels at HAY and BEN. The absolute voltage TOV limit envelopes create an upper bound for the voltage ratio TOV criteria. The absolute voltage limit envelopes for HAY and BEN differ in magnitude due to different pre disturbance voltages assumed at HAY and BEN.

- At HAY the pre disturbance steady state voltage is permitted to be as high as 1.1 p.u.
- At BEN the assumption is that the generation at and near BEN can manage the pre disturbance steady state voltage to approximately 1.0 p.u.

The voltage ratio TOV FRT criteria remain the same for both HAY and BEN.

The proposed TOV FRT requirements at HAY and BEN are taken from the HVDC TOV voltage ratio criteria and are shown as a ratio of post disturbance voltage to pre disturbance voltage in Figure 8 below.

At HAY and BEN the voltage ratio shall not exceed 1.3 for 0.06 seconds (3 cycles), gradually lowering to 1.2 just before 0.5 seconds (25 cycles), then stepping down to the greater of 1.1 ratio or 1.2 p.u. absolute at 0.5 seconds (25 cycles) to intersect with the TOV envelope set by the loss of motor load during a fault.

The TOV ratio is independent from the pre disturbance voltage at HV transmission level. The pre disturbance voltage level at LV or generator busses may be managed by tapping supply bank and/or generator transformers to manage the post disturbance voltage at those busses.

The TOV ratio resulting from the permanent loss of the HVDC bipole, within the voltage ratio envelope, will be experienced at LV or generator busses. LV and generator busses close to HAY or BEN will experience the same magnitude TOV ratio as the HV transmission network at HAY or BEN. As studies have shown, the magnitude of the TOV ratio will reduce for busses remote from HAY and BEN.

Beyond the influence of the TOV created by the permanent loss of the HVDC bipole the TOV FRT requirement is set by the expected loss of motor load during a fault on the transmission network. A TOV FRT envelope has been determined from the results of studies to identify the worst case expected TOV resulting from motor load tripping.

At transmission busses beyond the influence of the TOV created by the permanent loss of the HVDC bipole the absolute voltage shall not exceed 1.2 p.u. for 2 seconds (100 cycles), then stepping down to 1.15 p.u. absolute at 2 seconds (100 cycles), and finally lowering to 1.1 p.u. absolute voltage at 6 seconds (300 cycles). See figure 9 below.

To determine the TOV FRT requirement at busses remote form HAY and BEN but under the influence of the HVDC bipole analysis using a time-domain simulation tool and incorporating the following set of assumptions will be required to determine the expected impact of the permanent loss of the HVDC bipole:

- All transmission equipment in-service.
- Lowest forecast Wellington demand (consisting of GZ8, i.e. all substations between BPE and HAY) and corresponding system demand.
    - The impact of a permanent loss of the HVDC bipole is most pronounced at low demand periods.
- All reactive equipment for bipole operation and maximum transfer capability is available and in-service at HAY and BEN.

  - The impact of a permanent loss of the HVDC bipole is due in a large part, and most pronounced, when all required reactive support and filtering for the HVDC bipole is in service.
- HVDC north transfer approximately 1200MW, sufficient to cause a TOV that touches the envelope at the HVDC terminal in the island power system being studied.
  - With the TOV at HAY or BEN set to maximum allowed the worst case TOV at busses under the influence of the permanent loss of the HVDC bipole can be determined.
- All generation between BPE and HAY out of service and disconnected. Generation in the Waitaki hydro system around BEN minimised as far as possible while maintaining acceptable voltage support and reserve provision.
  - With the generation in the areas of the grid under the influence of the permanent loss of the HVDC bipole the worst case TOV at busses in those areas can be determined.

The proposed TOV FRT requirements are intended to apply to the HV transmission network.

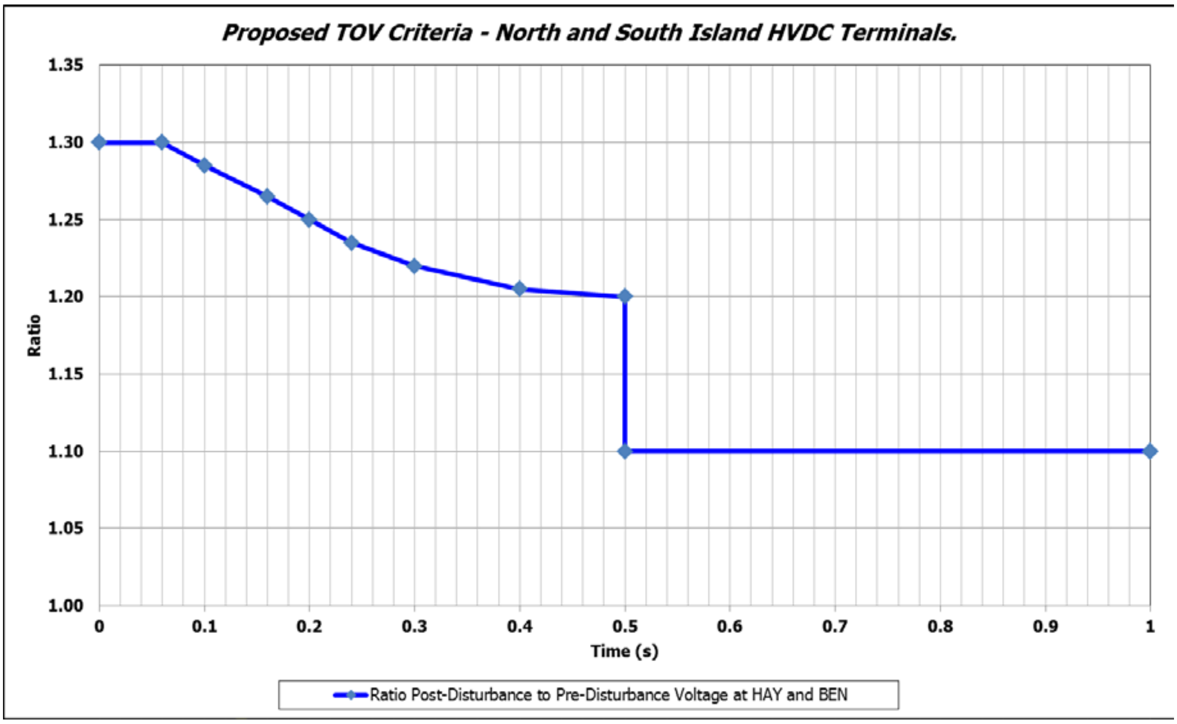


Figure 8: Proposed TOV FRT envelope at HAY and BEN.

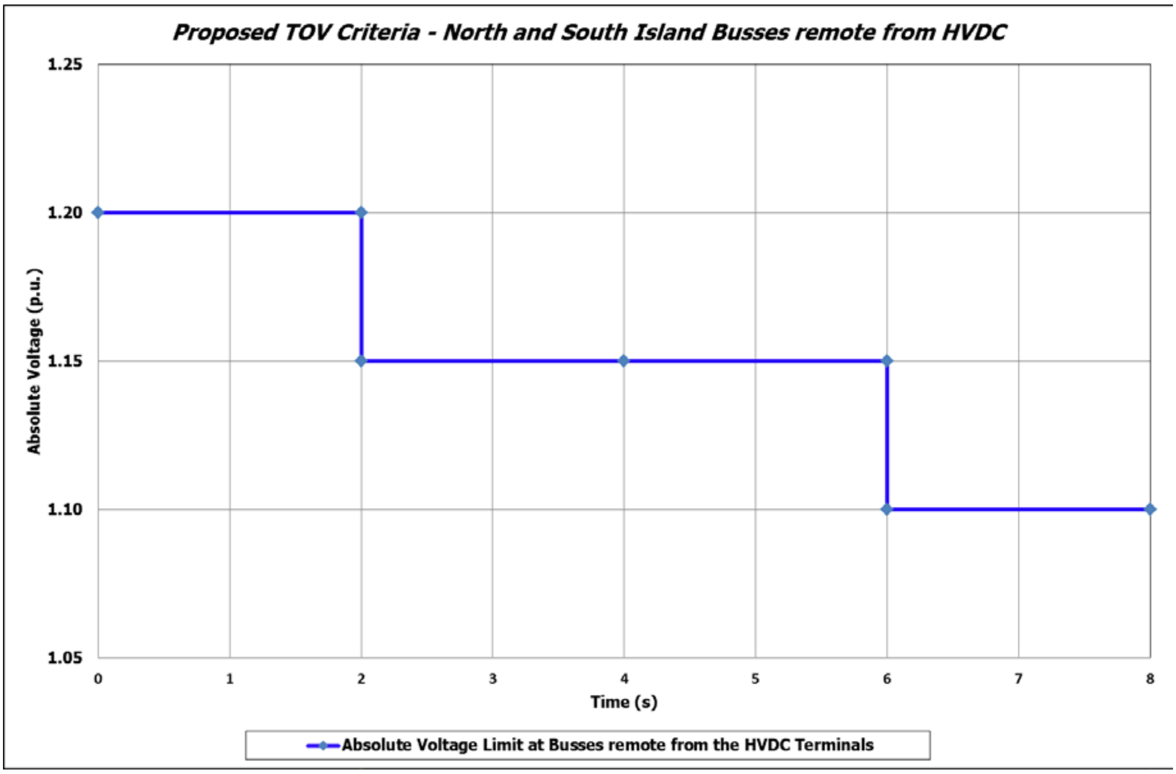


Figure 9: Proposed TOV FRT envelope at busses remote from the HVDC terminals.

4 Conclusions and Recommendations

Based on submissions received in response to the original FRT proposal, the System Operator has revised the TOV FRT requirements. This revision consists of updated assumptions and studies to measure system performance for the loss of the HVDC bipole.

The Transpower HVDC TOV criteria have been considered in the analysis and have been used to develop the proposed FRT requirements at HAY and BEN. A permanent bipole loss results in the worst case system TOV and the magnitude of this TOV will reduce for busses remote from the HVDC stations.

Beyond the influence of the TOV created by the permanent loss of the HVDC bipole the TOV FRT requirement is set by the expected loss of motor load during a fault on the transmission network.

The proposed TOV FRT requirements to be applied to the HV transmission network for the North and South Island power systems are shown in Figure 8 and Figure 9 above.

At HAY and BEN the ratio of post disturbance to pre disturbance voltage shall not exceed 1.3 for 0.06 seconds (3 cycles), gradually lowering to 1.2 just before 0.5 seconds (25 cycles), then stepping down to the greater of 1.1 ratio or 1.2 p.u. absolute at 0.5 seconds (25 cycles) to intersect with the TOV envelope set by the loss of motor load during a fault.

At transmission busses beyond the influence of the TOV created by the permanent loss of the HVDC bipole the absolute voltage shall not exceed 1.2 p.u. for 2 seconds (100 cycles), then stepping down to 1.15 p.u. absolute at 2 seconds (100 cycles), and finally lowering to 1.1 p.u. absolute voltage at 6 seconds (300 cycles).

Transmission busses under the influence of the TOV created by the permanent loss of the HVDC bipole will require analysis using a time-domain simulation tool and incorporating the set of assumptions listed in section 3.3 above.

5 References

[1] Consultation Paper, Generator Fault Ride Through, Electricity Authority, December 2010

[2] Generator Fault Ride Through (FRT) Investigation Stage 2, System Operator, 4 May 2010

6 Appendix

The following references to the HVDC criteria are taken from the New Zealand Inter Island HVDC Pole 3 Project Contract Document, Volume 2, Chapter 5, Clauses 6.1.1, 8.3.13, and 8.3.14, Transpower Grid Owner, 30 October 2009.

6.1 Clause 6.1.1 - Supply Voltage Conditions

Voltage limits at the Benmore 220 kV and Haywards 220 kV and 110 kV busses are shown in Table 6.1-2. Note that the supply voltage design criteria for Pole 2 are provided in Chapter 6. In many instances the Pole 2 design criteria are different to the Pole 3 design criteria.

Table 6.1-2Supply Voltage Conditions

Characteristic	Benmore	Haywards 220 kV	Haywards 110 kV
Nominal AC system voltage, line-to-line	220 kV	220 kV	110 kV
Normal Maximum continuous AC system operating voltage	242 kV	242 kV	114 kV
Normal Minimum continuous AC system operating voltage	209 kV	209 kV	110 kV
Extreme Minimum continuous AC system operating voltage	0.9x220 kV	0.9x220 kV	0.9x110 kV
Extreme Maximum continuous AC system operating voltage	245 kV	245 kV	123 kV
Maximum short-time AC system voltage for rating purposes	1.45 x 220 kV for 0.2 sec	1.45 x 220 kV for 0.2 sec	1.45 x 110 kV for 0.2 sec

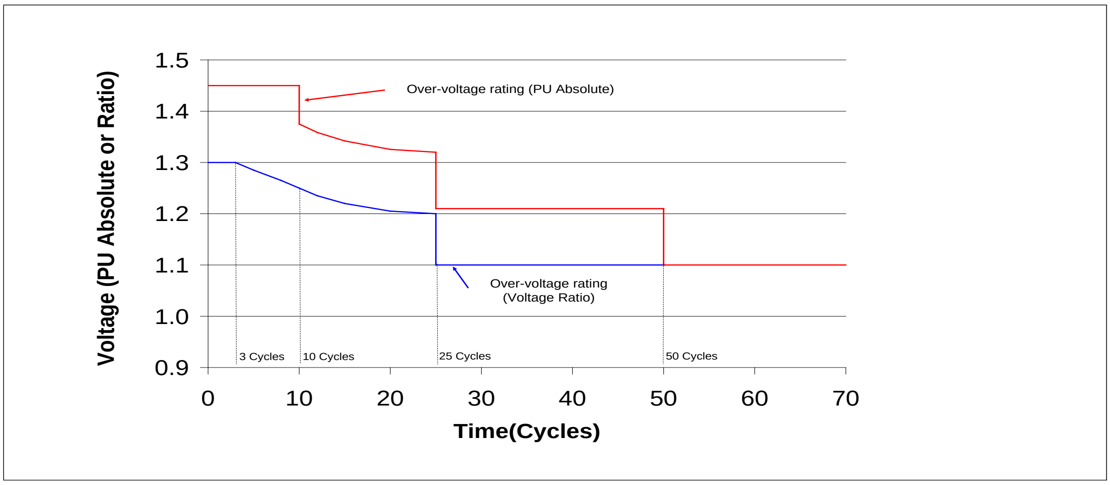
Figure 6.1-1 shows the two fundamental frequency overvoltage envelopes that apply at the Benmore 220 kV and Haywards 220 kV busses. One over-voltage envelope is defined in terms of the absolute p.u. voltage; the other over-voltage envelope is defined in terms of the ratio of post-disturbance voltage divided by the pre-disturbance voltage. In addition to the fundamental frequency over-voltage, there may also be oscillatory voltage components.

The voltage ratio envelope is 1.3 for 3 cycles, gradually lowering to 1.2 at 25 cycles, then stepping down to 1.1 for an indefinite time.

The absolute voltage envelope is 1.45 p.u. for 10 cycles, stepping down to 1.375 p.u. at 10 cycles, gradually lowering to 1.320 p.u. at 25 cycles, stepping down to 1.21 p.u. at 25 cycles, staying at 1.21 p.u. until 50 cycles, then stepping down to 1.1 p.u. for an indefinite time.

If an event occurs that causes a system disturbance, then all equipment within the scope of supply shall not trip (unless necessary to limit the over-voltage) and shall continue operation within the inherent capability of the equipment if the voltage stays within both the absolute envelope and ratio envelope shown in Figure 6.1-1.

Figure 6.1-1 Fundamental Frequency Overvoltage Envelope at Benmore and Haywards



6.2 Clause 8.3.13 - Overvoltage Performance Requirements

The overvoltage performance requirements are based on accommodating the rating of the existing Pole 2 equipment.

The Pole 2 equipment is designed for overvoltages when the valves are blocked not exceeding:

(a) At Haywards 220 kV bus 1.45 times 220 kV rms for 200 ms

(b) At Benmore 220 kV bus 1.30 times 220 kV rms for 200 ms

Also, the Pole 2 converter valves are designed to deblock and restore power transfer without damage for a fundamental frequency overvoltage defined by the ratio envelope shown in Figure 8.3-4. The rated overvoltage for Pole 2 is defined in terms of the ratio of the post disturbance voltage / pre-disturbance voltage. The voltage ratio shall not exceed 1.3 for 3 cycles, gradually lowering to 1.2 just before 25 cycles, then stepping down to 1.1 at 25 cycles, and finally lowering to the lesser of 1.1 ratio or 1.1 p.u. absolute after 50 cycles.

The Contractor shall provide necessary control functions to inhibit the start or restart of the Pole 2 converters until the overvoltage on the valve side of the Pole 2 converter transformers has dropped below a value which is within the capability of the equipment.

The duration of the TOV ratio and absolute TOV following an ac disturbance shall be reduced as quickly as possible by restarting the Pole 3 and Pole 2 converters and restoring dc current flow. The overvoltage shall be limited to below the performance characteristic shown in Figure 8.3-4. All 220 kV and 110 kV bus positive sequence voltages shall remain below this performance characteristic during recovery from faults.

6.3 Clause 8.3.14 - Overvoltage Rating and Withstand Requirements

For the purpose of determining overvoltage withstand rating, all equipment in the scope of supply shall be designed to withstand, without damage, the stresses resulting from the following overvoltage and restart events:

a) a fundamental frequency overvoltage lasting for a duration of 200 milliseconds due to full dc system load rejection up to the following levels.

   i. At Benmore 220 kV bus 1.45 times 220 kV rms

   ii. At Haywards 220 kV bus 1.45 times 220 kV rms plus any oscillatory voltage that may be present, following complete interruption of DC power transmission. The initial overvoltage is followed by a voltage reduction according to Figure 8.3-4.

b) deblock and restoration of Pole 3 dc power transfer (or reactive absorption for the SVS) at a maximum fundamental frequency overvoltage of 1.45 times 220 kV rms plus any oscillatory voltage that may be present for the time duration that the overvoltage can persist. In designing the valves, the Contractor shall take into account the possibility that the converter transformer or SVS transformer may be operating at off-nominal tap and the voltage on the valve side of the converter transformer or on the low voltage side of the SVS transformer may exceed 1.45 p.u.

c) continued operation to reduce or maintain the overvoltage ratio to below the performance limits given in Figure 8.3-4 as quickly as possible. The converter or SVS shall continue in operation and shall not block during temporary overvoltage events in which the temporary overvoltage ratio does not exceed the rating values and durations indicated in Figure 8.3-4.

In addition to the design requirements for temporary overvoltages given above, the Contractor shall provide a coordinated design of Pole 3 converter and other required equipment to withstand, without damage, the temporary overvoltages arising from the clearing of AC system faults and from transformer energization, as determined in studies performed by the Contractor.

All circuit breakers that are required to trip in order to limit overvoltages to within the performance envelope or as a protective action in the event that the overvoltage limiting function or equipment does not operate shall be rated for the overvoltage switching duty.

Figure 8.3-4 Overvoltage Withstand and Performance Requirements