ELECTRICITY AUTHORITY
TE MANA HIKO

3 September 2018

[redacted]

[redacted]

Dear [redacted]

OIA request - 2 March 2017 South Island AUFLS event

I refer to your request under the Official Information Act 1982 (OIA) for the following information about the 2 March 2017 South Island AUFLS event (2 March 2017 event):

- the System Operations Committee's (SOC) and the Security and Reliability Council's (SRC) feedback to Transpower New Zealand Limited (Transpower) on Transpower's report into the 2 March 2017 event
- the most recent reports by both Transpower and the Electricity Authority on the 2 March 2017 event considered by the Authority Board or Board sub-committee(s).

Below is a table that sets out the information you have requested.

Requested	Comment	Documents
1. Feedback from SOC to Transpower	Although the SOC has not provided written feedback to Transpower, it provided verbal feedback at the 7 December 2017, 22 February 2018, and 27 June 2018 SOC meetings, at which Transpower staff were present.	The feedback provided at the meetings is recorded in the meeting minutes. Parts of the minutes have been redacted because they are outside the scope of your request. The parts of the minutes that are covered by your request are released in full.
2. Feedback from SRC to Transpower	Although the SRC has not provided written feedback to Transpower directly, it wrote a letter to the Authority's Board, which the Authority then forwarded to Transpower. The SRC also provided verbal feedback when it discussed the event at its meeting on 13 December 2017, at which	The letter from the SRC to the Authority is released in full. The feedback provided at the meeting is recorded in the meeting minutes. Parts of the minutes have been redacted because they are outside the scope of your request. The parts of the minutes that are covered by your request are

Level 7, ASB Bank Tower, 2 Hunter Street, PO Box 10041, Wellington 6143, New Zealand TEL + 64 4 460 8860 FAX + 64 4 460 8879 WEB www.ea.govt.nz

Requested	Comment	Documents
	Transpower staff were present.	released in full.
3. Most recent report by Transpower to the Authority Board	The most recent report from Transpower considered by the Authority's Board is an appendix to the report covered by question 4 below.	Released in full.
4. Most recent report by EA to Board	The most recent report from the Authority to its Board was a paper attaching a consultation paper in relation to determining the causer for the under-frequency event. The Board considered the report at its 4 October 2017 meeting.	Parts of the Board paper, and an attachment to the paper, have been withheld under section 9(2)(h) of the OIA, on the grounds that it is necessary to protect legal professional privilege.
5. Most recent report by Transpower to SOC	The most recent report from Transpower to the SOC is a PowerPoint presentation that Transpower provided to the SOC at the 7 December 2017 meeting.	The PowerPoint presentation is released in full.
6. Most recent report by EA to SOC	The most recent report provided by Authority staff to the SOC is a two page report, that attached two further documents: • a draft report from Transpower dated June 2018 • an action list from Transpower	The two page document is released in full, as is the draft report from Transpower. The action list is attached, but the names of the individuals listed have been withheld under section 9(2)(a) of the OIA, to protect the privacy of natural persons.
7. Most recent report by Transpower to Compliance Committee	Transpower has not reported to the Compliance Committee	This part of your request is declined under section 18(e) of the OIA, on the grounds that the documents do not exist.
8. Most recent report by EA to Compliance Committee	The most recent reports by Authority staff to the Compliance Committee are two reports that the Committee considered at its meeting on 28 June 2018. One relates to alleged breaches by the grid owner, and the other relates to alleged breaches by the system operator.	Both papers are released in full.

Your request has been assessed in accordance with the OIA. As noted in the table above, the Authority has decided to withhold some information under section 9 of the OIA, on the grounds of protecting the privacy of individuals, and protecting legal professional privilege. In each of these cases I have also considered whether there is any public interest in releasing the information that would outweigh the potential harm that could be caused. I have decided that there is not.

For the information listed in row 7 above, your request is refused under section 18(e) of the OIA because the information does not exist.

You are entitled to ask an Ombudsman to investigate and review these decisions not to provide you with some of the information you requested. The address for contacting the Office of the Ombudsman is:

Office of the Ombudsman
PO Box 10-152
WELLINGTON

Yours sincerely

R Blundell.

Rory Blundell
Acting Chief Executive

Electricity Authority Board

MINUTES OF THE MEETING OF THE SYSTEM OPERATIONS COMMITTEE

Held on 07 December 2017 commencing at 8.59am

At Level 7, ASB Bank Tower, 2 Hunter Street, Wellington

Present:	Sandra Gamble (Chair) Lana Stockman Allan Dawson
In Attendance:	Carl Hansen, Chief Executive (until 11.30 am) Rory Blundell, General Manager Market Performance Grant Benvenuti, Manager Market Operations Callum McLean, Adviser System Operations Doug Watt, Manager Market Monitoring (10.30-11.38 am) David Hume, Engineering Adviser (10.30-11.38 am) John Clarke, General Manager System Operations, system operator (from 9.35am) Nick Coad, Business Improvement Manager - Delivery, Transpower (10.30-11.38 am) Dan Twigg, System Operations Manager, system operator (10.30-11.38 am) Clive Bull, Principal Consultant, Strata Energy Consulting (10.30-11.38 am) [redacted] Leigh Westley, Markets and Business Manager (from 9.35 am) [redacted]
Apologies:	Mark Sandelin

[redacted]

[redacted]

[redacted]

[redacted]

8. The 2 March 2017 South Island grid islanding event

8.1 System operator staff noted:

(a) It has taken too long to prepare this report.

(b) Actions are underway.

(c) The report is a summary intended for general distribution.

(d) They have feedback on the Authority's cover paper.

(e) They are targeting 1 February 2018 for eventual publication.

8.2 The system operator tabled a slide presentation (Annex 1 to these minutes) and spoke to the slides while answering occasional questions from the Committee.

8.3 The system operator summarised the event.

8.4 The system operator noted the investigation used the Incident Cause Analysis Method (ICAM), sometimes known as the 'swiss cheese' approach. This is similar to Transpower's bowtie methodology for risk management.

8.5 Committee members noted:

(a) the unsuitability of Autosync raises questions about Transpower's design and acceptance process for software tools

(b) the report could have better drawn out the human factors of the event.

Carl Hansen departed the meeting at 11.30 am

8.6 In response to system operator staff saying that Meridian were told to maintain the lower-South Island frequency at 50 Hz, Authority staff noted that Meridian assert they were told to follow "economic dispatch".

8.7 Authority staff summarised that:

(a) the seriousness of this event is hard to overstate as the potential damage could have been immense

(b) they will seek copies of call logs to establish the facts about what Meridian were instructed to do

(c) the risks involved in this event were known. The controls that were in place were not as effective as Transpower believed they were. This was a stressful event and the coordinators were let down by the controls relating to Autosync

(d) it is important to improve the transparency of the findings and lessons of this event.

8.8 The Chair concluded the discussion, noting that:

(a) the Committee encourages Transpower to prepare future reports earlier, as this gives confidence and certainty to the electricity market

(b) this public-facing summary document could have been more self-reflective, as the full ICAM report likely is.

8.9 The Committee requested that the system operator provide the Authority with the ICAM report.

Action point	The system operator will provide the Authority with the ICAM report on the 2 March 2017 South Island grid islanding event.

Dan Twigg, Nick Coad, Doug Watt, David Hume and Clive Bull departed the meeting at 11.38 am, [redacted]

[redacted]

Electricity Authority Board

MINUTES OF THE MEETING OF THE SYSTEM OPERATIONS COMMITTEE

Held on 22 February 2018 commencing at 9.01 am

At Level 7, ASB Bank Tower, 2 Hunter Street, Wellington

Present:	Sandra Gamble (Chair) Lana Stockman (from 9.08 am) Mark Sandelin (by teleconference) Allan Dawson
In Attendance:	Carl Hansen, Chief Executive Rory Blundell, General Manager Market Performance Grant Benvenuti, Manager Market Operations Callum McLean, Adviser System Operations Buddy Keirsey, Programme Manager Tim Street, Manager Wholesale Markets John Clarke, General Manager System Operations, system operator (9.50-11.00 am) Leigh Westley, Market and Business Manager, system operator (9.35-11.00 am) Scott Avery, Risk and Compliance Manager, system operator (9.35-11.00 am) Paul Hume, Network and Security Services Manager, Transpower (9.35-11.00 am) Anu Nayar, Partner - Risk Advisory, Deloitte (9.35-11.00 am) [redacted]
Apologies:	

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

12. 2 March 2017 event review

12.1 The Chair introduced the topic, noting that reporting is going to the Authority Board.

12.2 The Committee noted:

(a) Transpower's presentation on 6 December 2017 did not provide clear findings and learnings of the event. The Committee struggled to see the links from observations to lessons to actions.

(b) the performance of the system operator with respect to restoration on the day of the event is an area of concern

(c) the post-event reporting from Transpower has been unsatisfactory because of its timing and not transparently acknowledging responsibility.

(d) Transpower appeared not to have examined control room call recordings by December 2017

(e) the disparity between being told an ICAM methodology was followed but no ICAM report being produced was an unwelcome surprise

(f) it was taking this opportunity to reinforce to the system operator and all of Transpower that this event is of acute interest to the Committee members.

12.3 System operator representatives noted:

(a) an agreed commitment to review the review process itself

(b) the event is an excellent learning opportunity

(c) that Transpower would need to think carefully about the existing report, getting the effort and focus right

(d) Transpower wants its report to satisfy the Authority.

12.4 The Chair reminded the system operator that the Authority reserves the right to produce its own report if the Transpower report does not adequately address the Authority's concerns.

12.5 The Chair thanked the system operator staff for their constructive engagement and resilience. The Committee appreciated the discussion and it values that kind of discussion in the relationship.

System operator representatives departed the meeting at 11.00 am.

[redacted]

Electricity Authority Board

MINUTES OF THE MEETING OF THE SYSTEM OPERATIONS COMMITTEE

Held on 27 June 2018 commencing at 2.00 pm

At Level 7, ASB Bank Tower, 2 Hunter Street, Wellington

Present:	Sandra Gamble (Chair) Allan Dawson Lana Stockman Mark Sandelin
In Attendance:	Rory Blundell, General Manager Market Performance Grant Benvenuti, Manager Market Operations Callum McLean, Adviser System Operations John Clarke, General Manager Operations and Innovation, Transpower
Apologies:	None

[redacted]

4. 2 March 2017 South Island AUFLS event

[redacted]

[redacted]

Transpower presentation

John Clarke joined the meeting at 2.16 pm.

4.5 The Chair invited John Clarke to present the report. Mr Clarke tabled a short presentation and spoke to the slides (Annex 1 to these minutes). Mr Clarke noted Transpower appreciated the Authority and the Security and Reliability Council (SRC) feedback on the previous report as the new version:

(a) has been overhauled

(b) goes deeper on the operational response to the event

(c) includes updated actions and five new actions including reviews of:

(i) SPD

(ii) the process for major event reviews

(iii) risk management.

4.6 The Chair asked what the current level of risk is that an event similar to that on 2 March 2017 could happen again. Mr Clarke noted that, while Transpower is continuing to implement the actions set out in its report, some have been completed and reduce the risk:

(a) a new process to assign a manager to coordinate event response when there is a major event

(b) improved understanding and use of Autosync

(c) sharpened up operational communications to reduce the opportunity for misunderstanding.

4.7 Mr Clarke noted that:

(a) an independent person listening to the taped conversations was valuable

(b) Meridian Energy have some concerns with the report and some further changes based on Meridian's feedback should be expected.

4.8 A member noted the report used the words 'unintuitive' and 'impractical' to describe grid owner processes and cited the difficulties of getting senior protection experts. Given that, the member asked how confident the system operator was that grid owner system/network risks don't occur elsewhere. Mr Clarke responded that:

(a) the system operator has seen the Barry Hayden report[1], the post event actions, and put a hold on some outages

(b) the system operator takes comfort from the post-event actions that risks are being treated differently.

4.9 A member asked whether the system operator would procure more ancillary services if it perceived an increased risk. Mr Clarke responded that the system operator's first approach with any asset owner is to plan to avoid the risk, but it would procure more if needed.

4.10 A member questioned how best to encourage the grid owner to improve and whether the system operator should or would document any concerns it has with the grid owner and advise the Transpower CEO. The member considered that real-time remodelling of SPD should be workable at any time, not just during major events, to ensure HVDC assumptions are realistic at all times. The member considered that real-time pricing would exacerbate the importance of this. Mr Clarke thanked the member for the feedback and noted taking that approach with the grid owner runs the risk of second-guessing the information provided by asset owners, and increasing the perception that the system operator is treating the grid owner differently/favourably.

4.11 A member asked how outsiders will know if the action 'to agree an approach' was meaningfully completed. Mr Clarke noted his intention to enhance the wording of that action before the report is published to make it more objectively defined.

4.12 The Chair asked for the system operator's quarterly operational reports to include updates on actions. Mr Clarke agreed.

Action point	System operator to include progress on the actions arising from its report on the 2 March 2017 event in its quarterly operational report.

4.13 The Chair noted that the report highlighted material deficiencies in the system operator's risk management and assurance system, and it may be reasonable to infer that the 2 March 2017 event is not the only type for which controls are not yet in place or are ineffective.

[1] Barry Hayden is the independent expert from BEC Consulting that Transpower engaged to review the events as part of the investigation.

4.14 In response to members' comments, Mr Clarke noted:

(a) the Electricity Industry Participation Code contains a pretty good standard for formal communication

(b) Transpower learned lessons about improving the effectiveness of controls, especially those controls fully reliant on humans

(c) the Transpower Board is demanding improved risk management and more consistency of risk management across the organisation.

4.15 A member commented that the circumstances suggest there may be a cultural aspect to the event whereby coordinators felt undue pressure to return to economic dispatch as soon as possible.

4.16 The members and attendees discussed the way the Autosync software was used in this instance, and the changes made to achieve correct usage, including the inclusion of the Autosync tool in the simulator training.

4.17 The Chair encouraged staff to identify and advise the Committee of what the Authority can learn from the event in terms of:

(a) confirming the Authority's expectations of the quality and timing of post-event review reports

(b) monitoring and measuring system operator performance under the current System Operator Service Provider Agreement (SOSPA)

(c) evolution of the SOSPA in the future.

4.18 Mr Clarke noted that the system operator remains open to having a 'mature conversation' about payments of performance incentives in a year during which its performance during a major power system event was agreed to be unsatisfactory.

John Clarke departed the meeting at 3:07 pm

[redacted]

[redacted]

14 February 2018

Dr Brent Layton
Chair
Electricity Authority
PO Box 10041
Wellington 6143

Dear Brent

Advice resulting from 13 December 2017 meeting of the SRC

The Security and Reliability Council (SRC) is tasked with providing the Electricity Authority with independent advice on the performance of the electricity system and the system operator, and reliability of supply issues.

On 2 March 2017, a major event occurred on the power system (the event). At its 13 December 2017 meeting, the SRC considered and discussed papers and presentations from its secretariat and Transpower concerning the event. This letter is the SRC's advice arising from those papers and presentations.

Background to the 2 March 2017 event

The event essentially consisted of two major incidents: the tripping of Clyde-Twizel transmission circuits that electrically split the South Island and resynchronisation to reconnect the South Island back together.

The tripping of the Clyde-Twizel circuits during planned protection

Key factors were the test technicians being unaware of a recently installed 'intertrip' function, and being unable to observe the consequences of their test of the first circuit's protection equipment before proceeding with the equivalent test on the second circuit.

Potentially hazardous resynchronisation

Key factors were Transpower's failure to fully understand the process for undertaking resynchronisation and, prior to understanding the causes of the initial incident, proceeding to offer the Clyde-Twizel circuits for use and resynchronising the lower- and upper-South Island. Restoration was made more complicated by the system operator miscommunicating generation dispatch instructions and dispatching software that, apparently, cannot be updated quickly to reflect the changed grid configuration after the initial incident.

The primary outcomes to New Zealand from the event were:

- Some consumers in the upper-South Island having their power cut off to protect the entire power system.
- Potential damage to generators due to the out of phase resynchronisation.
- Some commercial and industrial consumers in the North Island having to instantaneously reduce their usage in accordance with their voluntary contractual arrangements.

Overall, most systems operated as intended and electricity supply was restored expeditiously.

Advice on the 2 March 2017 event

The SRC observed a few points of disagreement between the two presentations it received. Some differences of opinion should, in general, be expected. However, it was not obvious to the SRC that these few disagreements were irreconcilable and encourages the presenting parties to seek agreement where possible. The SRC found this to be unsatisfactory, but notes that this approach enabled it to review the event reports much earlier than otherwise.

The SRC's advice to the Authority about Transpower's event reports is that:

- This event does not seem to have been so complicated to have warranted taking so long to only have a draft report over nine months later.
- The use of independent investigators for some parts of the investigation was a positive step toward promoting objectivity in its reporting.
- The SRC has no disagreement with any of Transpower's recommendations or actions.
- The SRC agreed with Transpower's views that transparent and low risk maintenance of protection systems should be an important design criterion and that opportunities for improvement have been identified.
- The SRC considers that the reporting was not comprehensive and there are other aspects of the event that should be included.
    - As Transpower acknowledged to the SRC, its reporting is predicated on a misapprehension about what verbal dispatch instructions were given. The final report should include the latest information about communication of dispatch instructions.
    - There is a trade-off between making rapid restoration decisions to enable supply to be restored as soon as possible and the consequent higher risk of these decisions leading to adverse outcomes. In this case, there was an adverse outcome—a risk of damage to power system assets. The SRC suggests Transpower review whether its coordinators would benefit from improved guidance about what information they require to proceed with the various steps of system restoration. The SRC notes that such guidance will become more valuable as systems become more complex and automated, because events are more likely to be unusual and difficult to resolve.
    - The reporting should be clear about the system and grid coordinators being given an opportunity to give their views on the investigation outcome. The detail of those views may not need to be in the reporting, as the main intended benefit comes from the coordinators having a direct line to the Transpower Board. Knowing that those people have a strong voice to validate or criticise Transpower's overall conclusions would provide assurance about the suitability of the lessons learned and associated action plan.
- The SRC considers that Transpower should, in addition to its existing list of actions:
    - Improve the transparency of its next steps. Transpower should have a plan that sets out its actions. That plan should be publicly available and/or reported through to one or more of Transpower's regulators.
    - Identify the generic lessons from the event and promote these to other relevant organisations, such as those in the supply-side of the electricity industry.

- Initiate a discussion of this event by system and grid coordinators with their industry peers, possibly as part of, or as an adjunct to, the Process Safety Working Group in the StayLive forum.[1]

The SRC's advice to the Authority about the performance of the system operator is that:

- The system operator acknowledges that its resynchronisation of the South Island was not performed in the manner it expects of itself. This was a multi-causal decision and several controls were shown to be inadequate. Resynchronisation is a rare but core responsibility for the system operator. The risks of resynchronisation (given it had never been done and the potential asset damage) warranted better preparation from the system operator.
- The system operator acknowledges its verbal dispatch instructions to at least one key generator were the opposite of what it intended. There appears to have been no investigation at the time as to why the system was behaving differently from how the operators intended.
- The system operator has some limited responsibility of the shortcomings in the outage coordination process. The issues were predominantly the responsibility of the grid owner, though the system operator has ownership for the overall effectiveness of the process.
- The decision to resynchronise the South Island was made without knowing what had caused the Clyde-Twizel circuits to trip. It is not clear to the SRC whether it is reasonable to have expected the system operator to need to know the cause in these particular circumstances.
- The SRC is not aware of any other potential concerns that relate to the performance of the system operator.

The SRC's advice to the Authority about organisations undertaking post-event reporting is that:

- The primary focus of such reporting needs to be on identifying and communicating the lessons learned. To facilitate this focus, the reporting organisation needs to demonstrate openness and transparency.
- Event investigators should be mindful that the growing complexity of grids and their protection systems increases the challenge of ensuring that they operate as intended in unusual circumstances. As 'real time' grid operations become more complex it is possible that unintended situations will occur and there might be the need for control room operators to exercise judgement and question or clarify instructions.
- The SRC values being able to see how observations lead to lessons and how lessons lead to recommendations and actions. Publishing clear action plans and reporting on progress provides further transparency that promises are being kept.
- Lessons learned may have narrow or broad application. It is important for the reporting organisation to look for both, as the same observations can have both highly specific lessons and general lessons. Learning from a spectrum of lessons offers the greatest opportunity to improve security and reliability outcomes for electricity consumers.
- The reporting organisation needs to adopt an investigation methodology and know what high-level questions it wants to answer. This helps to guide the scope and usefulness of the eventual report.

The SRC's advice to the Authority about the secretariat's event report is that:

[1] http://www.staylive.nz/Site/staylive/Working-Groups/current-working-groups/process-safety.aspx

- The SRC has no disagreement with any of the secretariat's recommendations.
- The SRC received verbal advice that suggested the runback of the generation at Aviemore was satisfactorily responded to and actions taken. However, the Authority should satisfy itself whether additional investigation or reporting is warranted and, in any case, document its consideration of the matter.

This event was a combination of two significant system issues that, somewhat fortuitously, was managed reasonably expeditiously and where most systems and processes operated as intended. However, there are serious lessons to be learned from issues leading up to the initial event and from the restoration process. The SRC would like there to be a clear pathway forward with timelines for addressing the identified issues.

There is no further advice arising from the matters discussed at the SRC's 13 December 2017 meeting.

Yours sincerely

Mike Underhill
Chair
Security and Reliability Council

cc SRC members, Carl Hansen (Electricity Authority)

Security and Reliability Council ::: Meeting Number 22	
Venue ::: Level 7, ASB Bank tower, 2 Hunter Street, Wellington	
Time and date ::: 2:00 pm ::: 13 December 2017	

Minutes

Members present

::: Mike Underhill (Chair)
::: Anne Herrington
::: Barbara Elliston (by telephone)
::: Erik Westergaard
::: Guy Waipara
::: Nigel Barbour (by telephone, until 4:35 pm)
::: Vince Hawksworth (by telephone, until 4:25 pm)

Apologies

::: Bruce Turner
::: Marc England

In Attendance

Name	Title	Agenda item # attended
	Electricity Authority (Authority):	
::: Carl Hansen	Chief Executive	All
::: Rory Blundell	General Manager Market Performance	#3-#7 (from 2.21 pm)
::: Grant Benvenuti	Manager Market Operations	#3-#7 (from 2.21 pm)
::: Callum McLean	Adviser System Operations	All
::: Doug Watt	Manager Market Monitoring	#3-#7 (from 2.21 pm)
::: David Hume	Engineering Adviser	#3-#7 (from 2.21 pm)
	Transpower:	
::: John Clarke	System Operations General Manager	#3-#4 (2.21 pm until 3.58 pm)
::: Alison Andrew	Chief Executive	#3-#4 (2.21 pm until 3.58 pm)
::: Dan Twigg	System Operations Manager	#3-#4 (2.21 pm until 3.58 pm)
::: Nick Coad	Business Improvement Manager - Delivery	#3-#4 (2.21 pm until 3.58 pm)
	Other:	
Clive Bull	Principal Consultant, Strata Energy Consulting Limited	From 2.21 pm

[redacted]

2 March 2017 South Island grid islanding event

Transpower presentation

Alison Andrew, John Clarke, Dan Twigg, Nick Coad, Rory Blundell, Doug Watt, David Hume, Grant Benvenuti and Clive Bull joined the meeting at 2:21 pm.

4. Transpower staff spoke to a slide presentation. Some points noted were that:
   a. there was a minimal impact to consumers
   b. the event was very complex
   c. Transpower has other intertrip schemes, though the Clyde protection arrangements are very unusual
   d. Transpower is still working through and considering the Authority's feedback
   e. among process changes already made, Transpower has created a 12 week planning window for outage coordination of similarly complex situations
   f. it takes time for process changes to be fully embedded

Members in attendance via video conference switched to teleconference at 2:50 pm

   g. advice from protection experts was sought by controllers, but was not received during the event as it happened quickly
   h. economic dispatch is the lowest of the restoration priorities
   i. the 'autosync' software was not well named, as this overstates its capabilities beyond what was intended by its designers.
5. The Chair thanked Transpower for its presentation.

Authority presentation

6. The secretariat spoke about their key preliminary views on the event, highlighting some points with slides. Some points of discussion were:

a. Transpower's risk and asset management process had recognised the relevant risks. This event was enabled by the failure of risk controls

b. the automatic response from the power system was excellent and limited the impact on consumers

c. system coordinators gave unambiguous instructions for at least one lower South Island generator to follow economic dispatch when the system operator's intent was for lower South Island generators to ignore economic dispatch and maintain frequency.

7. The SRC asked questions of the presenters and discussed various matters including:

a. what system controllers were aware of, including their own dispatch communications

b. whether remodelling and redispatch of the power system was possible in a realistic time

c. the instructions to lower South Island generation to follow economic dispatch

d. the problems that can arise due to lack of situational awareness

e. time pressure is real and considerable

f. more automation making recovery from failure harder

g. what they key questions of Transpower's investigation were

h. what the system controllers thought about how they were supported

i. the value of control room operators working under pressure being willing and empowered to take time to prudently 'pause' and consider their next steps

8. Transpower noted its disagreement with two of the secretariat's preliminary views: outage planning, and use of the Autosync software.

9. The SRC agreed that Transpower should convene a meeting of control room staff from relevant organisations to have them discuss communication lessons and preferred alternatives.

10. The Authority Chief Executive noted the good discussion held.

All Transpower staff departed the meeting at 3:58 pm

[redacted]

[redacted]

[redacted]

Meeting date: 4 October 2017

Determining the causers of the 2 March 2017 under-frequency events

Prepared by: **Sarah Hughson**
Market Operations Coordinator

Date prepared: 11 September 2017

Determining the causers of the 2 March 2017 under-frequency events

1 Recommendations

1.1 It is recommended the Board:

(a) **approve** the draft determination that Transpower New Zealand Limited (Transpower), as the grid owner, was the causer of the first under-frequency event (UFE) on 2 March 2017

(b) **approve** the draft determination that Meridian Energy Limited (Meridian), as a generator, was the causer of the second UFE on 2 March 2017

(c) **delegate** to the Chief Executive the authority to finalise and publish the consultation paper *Draft determinations of the causers of the 2 March 2017 under-frequency events* (Appendix A)

(d) **approve** a consultation period of not less than six weeks beginning no later than 17 October 2017

(e) **delegate** to the Chief Executive the authority to publish the final determination after considering all submissions received, provided there are no material or contentious issues arising in submissions

(f) **note** the consultation paper seeks feedback on the system operator's proposed calculation of the event charge payable, though this does not form part of the Electricity Authority's (Authority) determination.

2 Rationale

2.1 Under clause 8.61 of the Electricity Industry Participation Code 2010 (Code), the Authority must publish a draft determination on the causer of an UFE and consult with participants substantially affected in relation to the draft determination.

2.2 Authority staff have considered the system operator's report of its investigations into the 2 March UFEs, including the system operator's correspondence with the grid owner and Meridian.

2.3 Authority staff analysis of information available (including legal advice from Duncan Cotterill) finds that:

(a) the system operator has not correctly interpreted the Code requirements for determining the causer of the first UFE

(b) Transpower, as the grid owner, meets the criteria in the Code definition of 'causer' for the first UFE.

2.4 Based on information available, and Meridian's acceptance as the causer, Authority staff concur with the system operator's finding that Meridian was the causer of the second UFE.

3 Next steps

3.1 If approved, the Chief Executive will publish the draft determination for a six-week consultation period from 17 October 2017 to 28 November 2017. The Authority's standard consultation period for UFEs is four weeks.[1] As this consultation includes a determination considered to be complex and/or contentious in nature, Authority staff instead propose a six week consultation.

3.2 After analysing any submissions, Authority staff will make a recommendation to the Chief Executive regarding a final determination.

3.3 If any material or contentious issues are raised in submissions, the Chief Executive will refer the final determination back to the Board for a decision.

4 Introduction

4.1 The normal frequency band in New Zealand is between 49.8 and 50.2 Hz. A UFE can only occur when the frequency falls below 49.25 Hz. Two UFEs occurred on 2 March 2017:

(a) the first at 11:21 am, when the frequency dropped to 49.17 Hz in the North Island

(b) the second at 11:24 am, when the frequency dropped below 49.25 Hz in the upper South Island (reaching to 48.52 Hz by 11.26 am).

4.2 Clause 8.60 of the Code requires the system operator to report to the Authority after a UFE to advise who the system operator considers caused the UFE. This report must include the system operator's reasons and all supporting information. Clause 8.61 of the Code then requires the Authority to determine and consult on the causer of a UFE.

4.3 As required under the Code, the system operator reported to the Authority setting out its views on the causers of the two UFEs on 2 March 2017. The system operator's final report to the Authority is attached in Appendix B.

4.4 The events of 2 March 2017 are more complex than those considered in previous determinations of UFE causer made by the Authority. An updated report was submitted by the system operator on 23 August 2017 after Authority staff requested further clarification on the system operator's original report.

4.5 The Code does not prescribe the length of time the system operator may take to investigate and request information from a participant about a UFE. The system operator is required to provide the report to the Authority within 40 business days (or longer as agreed by the Authority) of receiving requested information on an event from a participant. The original report was received on 19 June 2017, which was within 40 business days of the original receipt of the information. The review of the report by Authority staff led to further questions. Accordingly, Authority staff requested further information from the system operator and sought independent legal advice on the relevant Code definitions, before a draft determination could be presented to the Board.

5 Relevant Code definitions

5.1 The relevant Code definitions for this determination are "causer" and "under-frequency event" as follows:

causer, in relation to an **under-frequency event**, means—

(a) if the **under-frequency event** is caused by an interruption or reduction of electricity from a single **generator's** or **grid owner's asset** or **assets**, the **generator** or **grid owner**; unless—

[1] At its meeting on 15 December 2016, the Board approved a standard four week consultation period for determinations that are not considered to be complex or contentious.

(i) the **under-frequency event** is caused by an interruption or reduction of **electricity** from a single **generator's asset** or **assets** but another **generator's** or a **grid owner's** act or omission or property causes the interruption or reduction of **electricity**, in which case the other **generator** or the **grid owner** is the **causer**; or

(ii) the **under-frequency event** is caused by an interruption or reduction of **electricity** from a **single grid owner's asset** or **assets** but a **generator's** or another g**rid owner's** act or omission or property causes the interruption or reduction of **electricity**, in which case the **generator** or other **grid owner** is the **causer**; or

(b) if the **under-frequency event** is caused by more than 1 interruption or reduction of **electricity**, the **generator** or **grid owner** who, in accordance with paragraph (a), would be the **causer** of the **under-frequency event** if it had been caused by the first in time of the interruption or reduction of **electricity**; but

(c) if an interruption or reduction of **electricity** occurs in order to comply with this Code, the interruption or reduction of **electricity** must be disregarded for the purposes of determining the **causer** of the **under-frequency event**

under-frequency event means—

(a) an interruption or reduction of **electricity** injected into the **grid**; or

(b) an interruption or reduction of **electricity** injected from the **HVDC link** into the South Island **HVDC injection point** or the North Island **HVDC injection point**—

if there is, within any 60 second period, an aggregate loss of **injection** of **electricity** in excess of 60 **MW** (being the aggregate of the net reductions in the **injection** of **electricity** (expressed in **MW**) experienced at **grid injection points** and **HVDC injection points** by reason of paragraph (a) or (b)), and such loss causes the frequency on the **grid** (or any part of the **grid**) to fall below 49.25 Hz (as determined by **system operator** frequency logging).

6 The recommended draft determination is that the grid owner was the causer of the first UFE

The system operator recommended there was a UFE with no causer

6.1 In its report to the Authority, the system operator looked at two potential causers and concluded that there was no causer for the first UFE on 2 March 2017. The system operator's reasons for finding there was no causer are:

(a) In its communications with the system operator, the grid owner asserts the HVDC was acting in accordance with clause 8.17 of the Code when it ramped back transfer to the North Island.[2] This clause requires the HVDC owner to ensure that its assets make the maximum possible injection contribution to maintain frequency within the normal band (and to restore frequency to the normal band) at all times. Therefore, paragraph (c) of the Code definition of "causer" in clause 1.1 of the Code applies.

(b) The system operator also investigated whether Transpower, as the grid owner, was the causer of the event due to the disconnection of the Clyde-Twizel circuits. This disconnection is considered by the system operator to not meet the criteria of causer because it was an unplanned outage and was a reconfiguration of the grid rather than an interruption or reduction of electricity injected into the grid as a whole. The system

[2] Paragraphs 25–26 of Appendix B.

operator also believes that even if the disconnection was an interruption or reduction of electricity it did not occur at a grid injection point or HVDC injection point.[3]

(c) The system operator interprets paragraph (c) of the definition of "causer" to require the interruption or reduction of electricity from the HVDC link to be disregarded, not just for the purposes of that cause, but "…for the purposes of determining *any* causer of the under-frequency event".[4] Therefore, as Transpower is the legal entity that owns both the HVDC and the Clyde-Twizel circuits, there is not "another grid owner" as provided for in paragraph (a)(ii) of the Code definition of causer.[5]

Authority staff agree there was a UFE

6.2 On review of the information available, Authority staff assessed there was a chain of incidents that led to the first UFE. The first UFE was triggered when, during a planned outage of the Livingston-Naseby circuit, the two Clyde-Twizel 220 kV transmission circuits were unintentionally disconnected from the grid in quick succession. This caused the frequency in the lower South Island to increase to 53.6 Hz, and drop in the upper South Island to 47.40 Hz.

6.3 The HVDC acted in response to the upper South Island frequency drop that was caused by the two Clyde-Twizel circuits disconnecting from the grid. This response was to ramp back the injection into the Haywards HVDC injection point, and the North Island frequency then fell to 49.17 Hz. This was the first UFE.

Authority staff recommend that there was a causer

6.4 The Clyde-Twizel circuits are assets belonging to Transpower, as the grid owner, and failure of those assets meets the criteria in paragraph (a) of the definition of "causer".

6.5 The exception in paragraph (a)(ii) of the definition of 'causer' relates to situations where *another* grid owner or generator causes the first grid owner's interruption or reduction of electricity, so does not apply in the situation of the first UFE at 11.21 am (as the relevant circumstances do not involve any generators or any *other* grid owner). For example, had the HVDC been owned by another grid owner, the grid owner of Clyde-Twizel would be the causer.

6.6 Authority staff sought independent legal advice from Duncan Cotterill on the definition of "causer" in relation this UFE (Appendix C). The advice included the following:

[redacted]

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3 Paragraph 21 of Appendix B.

4 Paragraph 22 of Appendix B.

5 Paragraph 32 of Appendix B.

[redacted]

6.8 The operation of the HVDC link was an expected and appropriate action, therefore Authority staff do not consider the operation of the HVDC link to be a significant intervening event.

6.9 Authority staff recommend that the Authority's draft determination should be that Transpower, as the grid owner that owns the Clyde-Twizel circuits, was the causer of the first UFE.

Authority staff note the associated event charge is smaller than policy intended

6.10 The system operator used the 185.8 megawatt (MW) difference in HVDC transfer to the North Island to calculate the event charge for the first UFE. This follows the formula set out in clause 8.64.

6.11 Authority staff consider the policy intent of the UFE causer regime is to apply a higher event charge (based on ~400 MW lost during the interruption of electricity on the Clyde-Twizel circuits).

6.12 However, there is no viable interpretation of the Code where an event charge based on ~400 MW is reached. Therefore, the consultation has been based on the sound option of 185.8 MW.

6.13 Authority staff consider there is a deficiency in the phrasing in the definition of UFE and have confirmed this is in scope for the *Instantaneous reserve event charge and cost allocation* project. This deficiency is not discussed in the consultation paper because it is not relevant to determining the causer of the 185.8 MW UFE.

7 The recommended draft determination is that Meridian was the causer of the second UFE

7.1 Meridian own the Aviemore power station (Aviemore) in the upper South Island. While the generator governors at Aviemore were responding to the upper South Island frequency drop, a previously undiscovered incorrect software parameter caused the governors to ramp back generation. Although occurring in the aftermath of the first UFE, this issue was outside of the 60 second aggregate period allowed in the definition of a UFE, and is therefore considered a separate UFE.

7.2 As required under the Code, the system operator reported to the Authority setting out its view that Meridian was the causer of the second UFE. In correspondence with the system operator, Meridian has agreed with the system operator's view of the second UFE.

7.3 Authority staff concur with the system operator's findings, and therefore consider that the Authority's draft determination should be that Meridian was the causer of the second UFE.

8 Authority staff propose a six-week consultation period starting in October 2017

8.1 Authority staff have prepared a consultation paper for the purposes of consulting with substantially affected participants on the draft determinations, as required by clause 8.61(4).

8.2 As discussed in paragraph 3.1, Authority staff propose a six week consultation because the determination is complex and/or contentious in nature.

8.3 The consultation period is proposed for 17 October 2017 until 28 November 2017.

9 The consultation paper also invites comment on the system operator's calculation of MW lost

9.1 The system operator's report to the Authority includes the calculation to determine the MW lost during the first and second UFEs. The calculation is central to determining the event charges payable by the causers, and therefore also to the rebates paid to relevant participants in accordance with clause 8.69 of the Code.

9.2 Although the calculation is not part of the Authority's draft determination, we are seeking feedback on the system operator's calculation to enable any stakeholder to raise a concern about the calculation. Any concerns will be relayed to the system operator for consideration prior to the clearing manager generating related invoices.

10 Attachments

10.1 The following items are attached to this paper:

(a) Appendix A: Draft determinations of the causers of the 2 March 2017 under-frequency events

(b) Appendix B: The system operator's causation report on the 2 March 2017 under-frequency events

(c) Appendix C: Duncan Cotterill's legal opinion on the first of two under-frequency events on 2 March 2017.

Appendix A Draft determinations of the causers of the 2 March 2017 under-frequency events

The Authority's draft determinations of causers

Draft determinations of the causers of the 2 March 2017 under-frequency events

Consultation paper

Submissions close: 5pm 28 November 2017

11 September 2017

Executive summary

Two under-frequency events occurred on 2 March 2017

The Electricity Industry Participation Code 2010 (Code) requires the Electricity Authority (Authority) to determine the causer of an under-frequency event (UFE), and prescribes the process for making its determination (clause 8.61 of the Code).

The purpose of this paper is to:

(a) set out the Authority's draft determinations of the causers of the two 2 March 2017 UFEs

(b) consult with interested parties on the Authority's draft determinations.

These draft determinations are being consulted on in this single consultation paper due to the close timing of the UFEs.

The Authority's draft determinations

The Authority's draft determination under clause 8.61 is that Transpower New Zealand Limited (Transpower), as the grid owner, was the causer of the first UFE on 2 March 2017.

The Authority's reasons for this draft determination are:

(a) the first UFE was triggered during a planned outage of the Livingston-Naseby circuit, when the two Clyde-Twizel 220 kV transmission circuits disconnected from the grid in quick succession causing a reduction of energy into the North Island at the HVDC injection point

(b) as the grid owner that owns the Clyde-Twizel circuits, Transpower meets the definition of "causer" in Part 1 of the Code.

The Authority's draft determination under clause 8.61 is that Meridian Energy Limited (Meridian) was the causer of the second UFE on 2 March 2017.

The Authority's reasons for this draft determination are:

(a) the interruption or reduction of electricity on 2 March 2017 occurred at the Aviemore power station (Aviemore), which belongs to Meridian

(b) no other asset was identified as having caused or potentially caused this UFE

(c) in a reply to a system operator letter, Meridian has accepted that it was the causer of this UFE.

Submissions are invited from interested parties

The Authority must consult with interested parties before making its final determinations. Interested parties are invited to make a submission on the Authority's draft determinations by 5 pm on Tuesday 28 November 2017.

The Authority will consider submissions received and make a final determination on each UFE.

The Authority also invites comment on the system operator's calculation of the megawatts (MW) lost during the UFE, which the system operator uses for calculating the event charge for the UFE.

Contents

1 What you need to know to make a submission

What this consultation paper is about

1.1 The purpose of this paper is to consult with interested parties on the Authority's draft determinations that:

(a) Transpower was the causer of the first UFE on 2 March 2017 at 11.21 am, when the frequency dropped to 49.17 Hz in the North Island

(b) Meridian was the causer of the second UFE on 2 March 2017 at 11.24 am, when the frequency dropped below 49.25 Hz in the upper South Island (reaching 48.52 Hz by 11.26 am).

How to make a submission

1.2 The Authority's preference is 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—Draft determinations of the causers of the 2 March 2017 under-frequency events" in the subject line.

1.3 If you cannot send your submission electronically, post one hard copy to either of the addresses below, or fax it to 04 460 8879.

Postal address	Physical address
Submissions Electricity Authority PO Box 10041 Wellington 6143	Submissions Electricity Authority Level 7, ASB Bank Tower 2 Hunter Street Wellington

1.4 Please note the Authority wants to publish all submissions it receives. If you consider that we should not publish any part of your submission, please:

(a) indicate which part should not be published

(b) explain why you consider we should not publish that part

(c) provide a version of your submission that we can publish (if we agree not to publish your full submission).

1.5 If you indicate there is part of your submission that should not be published, we will discuss with you before deciding whether to not publish that part of your submission.

1.6 However, please note that all submissions we receive, including any parts that we do not publish, can be requested under the Official Information Act 1982. This means we would be required to release material that we did not publish unless good reason existed under the Official Information Act to withhold it. We would normally consult with you before releasing any material that you said should not be published.

When to make a submission

1.7 Please deliver your submissions by **5pm** on **28 November 2017**.

1.8 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 The Authority's draft determinations

Transpower, as the grid owner, was the causer of the first UFE

2.1 The Authority's draft determination under clause 8.61 is that Transpower, as the grid owner that owns the Clyde-Twizel 220 kV transmission circuits, was the causer of the first UFE on 2 March 2017 at 11.21 am.

2.2 The Code definitions for "causer" and "under-frequency event" are set out in Appendix C.

2.3 The system operator has investigated this UFE and reported to the Authority that:

(a) a UFE occurred when North Island frequency fell to 49.173 following a 185.8 MW reduction of electricity injected from the HVDC into the North Island

(b) that reduction of electricity occurred to support the frequency of the upper South Island complying with clause 8.17 of the Code, therefore paragraph (c) of the Code definition of "causer" applies

(c) in the system operator's view the first UFE has no causer.

2.4 Having considered the system operator's report and the relevant elements of the Code, the Authority (based on the information available to it at this time) concurs with the system operator's:

(a) description of the circumstances

(b) conclusion that an UFE occurred at 11.21 am

(c) view that the HVDC response to the falling frequency was to comply with the Code, and therefore paragraph (c) of the definition of "causer" applies (though we disagree with the scope of the system operator's application).

2.5 The Authority does not concur with the system operator's findings that there is no causer of the first UFE. On review of the events on 2 March 2017, the Authority has determined that Transpower, as the owner of the two Clyde-Twizel 220 kV transmission circuits, meets the definition of "causer".

2.6 When reaching this determination, the Authority considered each paragraph of the definition of "causer". The Authority considers that:

(a) The requirements of paragraph (a) are met because the disconnection of the Clyde-Twizel circuits was "…an interruption or reduction of electricity from a single…grid owner's asset…" that caused[1] the UFE.

(b) The exception in paragraph (a)(i) relates to situations caused by a single generator, so does not apply in the situation of the first UFE at 11.21 am (as the relevant circumstances do not involve any generators).

(c) The exception in paragraph (a)(ii) relates to situations where *another* grid owner or generator causes the first grid owner's interruption or reduction of electricity, so does not apply in the situation of the first UFE at 11.21 am (as the relevant circumstances do not involve any generators or any *other* grid owner).

[1] There is case law that is generally relevant to interpreting whether something caused another thing. Causation is a question of fact that can be best answered by ordinary common sense (rather than abstract theory) and in a way that is consistent with the objectives of the legislation (for example, see *Auckland Regional Council v URS New Zealand Limited* DC Auckland 16 April 2009, and the cases it refers to).

(d) The requirements of paragraph (b) are not met because, despite the disconnection of the Clyde-Twizel circuits being the "interruption or reduction of electricity" that was "first in time", the application of paragraph (c) (as discussed in paragraph 2.4(c) above) means the HVDC interruption or reduction of electricity must be disregarded. In which case there is not "more than 1 interruption or reduction of electricity" that caused the UFE.

(e) The exception in paragraph (c):

(i) Doesn't apply to the "interruption or reduction of electricity" on the Clyde-Twizel circuits because the trip of the Clyde-Twizel circuits did not occur in order to comply with the Code.

(ii) Does apply to the "interruption or reduction of electricity" on the HVDC (HVDC response) because it was required by clause 8.17 to assist in the prevention of cascade failure. Therefore, the Authority concludes that for the purposes of paragraphs (a) and (b) of the definition of "causer", it must disregard the HVDC response.

2.7 The Authority has also considered the system operator's interpretations of the Code included in its report. The Authority disagrees with the system operator's interpretations that:

(a) disregarding the interruption or reduction of electricity on the HVDC as required by paragraph (c) of the definition of causer means that no causer can ever be found[2]

(b) the "interruption or reduction of electricity" referred to in the definition of "causer" must be read as an 'interruption or reduction of electricity injected into the grid at a grid injection point or from the HVDC link at an HVDC injection point' (imported from a portion of the definition of "under-frequency event").[3]

Meridian was the causer of the second UFE

2.8 The Authority's draft determination under clause 8.61 is that Meridian, as a generator, was the causer of the second UFE on 2 March 2017 at 11.24 am.

2.9 The system operator has investigated this UFE (in accordance with clause 8.60), and has reported to the Authority that:

(a) the interruption/reduction of electricity on 2 March 2017 at 11.24 am occurred at Aviemore, which belongs to Meridian

(b) no other asset was identified as having caused or potentially caused the second UFE

(c) in the system operator's view, Meridian was the causer of this UFE.

(d) Meridian has accepted that it was the causer of this UFE.

2.10 Having considered the system operator's report and the relevant elements of the Code, the Authority (based on the information available to it at this time) concurs with the system operator's findings on the second UFE.

[2] Paragraph 22 of Appendix B

[3] Paragraph 21 of Appendix B

3 How the Authority reached this draft determination

The system operator investigated the causer of the first and second UFEs

3.1 Clause 8.60 requires the system operator to investigate the causer of a UFE and provide a report to the Authority.

3.2 The system operator has fulfilled its obligations under clause 8.60. The system operator's report to the Authority (dated June 2017) is attached as Appendix B of this draft determination. The report finds two UFEs occurred on 2 March 2017, which are summarised as follows:

(a) During a planned outage of one transmission circuit in the lower South Island, the remaining two circuits disconnected separating the South Island into two electrical islands. The frequency increased to 53.6 Hz in the lower South Island, and fell to 47.4 Hz in the upper South Island.

(b) Automatic under-frequency load shedding (AUFLS), generator governor response, and HVDC response responded to the fall in frequency in the upper South Island. Instantaneous reserves responded in both the North and South Islands.

(c) The HVDC responded to the reduced frequency in the upper South Island by reducing transfer into the grid from the HVDC North Island injection point, and at 11.21 am the North Island frequency fell to 49.17 Hz.

(d) The frequency fall and the quantum of MW lost (greater than the 60 MW de minimis set out in the definition for "under-frequency event) meant that a UFE, as defined in Part 1 of the Code, had occurred— this is the first UFE on 2 March 2017.

(e) The system operator considers:

(i) Transpower, as the grid owner, does not fit the Code definition of "causer" in relation to the disconnection of the Clyde-Twizel circuits

(ii) the HVDC owner is not the causer due to the effect of paragraph (c) in the Code definition of "causer".

(f) No other event was identified as contributing to or causing the first UFE. The system operator concluded there was no causer for the first UFE.

(g) As mentioned in paragraph 3.2(b) above, instantaneous reserve generation activated in the upper South Island and interruptible load and AUFLS tripped. One of the several generators that remained connected was Aviemore.

(h) Aviemore initially performed as expected and responded to the falling frequency by increasing its output. An incorrectly set parameter within the Aviemore control system reacted when the frequency reached 47.5 Hz. This caused the control mode of the governors to change from power control mode to speed control mode causing Aviemore generation to ramp down.

(i) At 11.26 am, five minutes after the first UFE, the reduction of generation at Aviemore caused the frequency in the upper South Island to fall to 48.52 Hz.

(j) The frequency fall and the quantum of MW lost (greater than the 60 MW de minimis) meant that a UFE, as defined in Part 1 of the Code, had occurred—this is the second UFE on 2 March 2017.

(k) Frequency was restored to the normal band quickly.

(l) No other event was identified as contributing to or causing the second UFE. The system operator concluded that Meridian was the causer for the second UFE.

3.3 The system operator report includes copies of the following correspondence with Transpower, as the grid owner:

(a) On 6 April 2017, the system operator wrote to Transpower, as the grid owner, setting out its view that the first UFE was initiated at the HVDC link resulting in a loss of injection. The system operator requested any information Transpower, as the grid owner, could provide on the UFE.

(b) On 16 May 2017, in a reply to the system operator, Transpower, as the grid owner, disputed that it was the causer of this UFE. The grid owner asserted the HVDC link acted in accordance with clause 8.17 to ensure the maximum possible injection contribution to maintain frequency within the normal band. Therefore paragraph (c) of the definition of "causer" applies, and the interruption or reduction of electricity must be disregarded in determining the causer.

3.4 The system operator report includes copies of the following correspondence with Meridian:

(a) On 6 April 2017, the system operator wrote to Meridian setting out its view that the second UFE was initiated at Aviemore resulting in a loss of injection, and requesting any information Meridian could provide.

(b) In a reply to the system operator, Meridian agreed it was the causer of the second UFE. Meridian did not provide any further information.

The Authority has considered the system operator's report

3.5 Clause 8.61(2) requires the Authority to publish a draft determination that states whether a UFE was caused by a generator or grid owner, and, if so, the identity of the causer. Clause 8.61(3) requires the Authority to give reasons for its findings in the draft determination.

3.6 The Authority has considered the system operator's report and liaised directly with system operator staff in relation to the system operator's investigation and report.

3.7 Based on the information available to it, the Authority does not concur with the system operator's findings that there was no causer of the first UFE of 2 March 2017 at 11.21 am. The Authority's draft determination and reasons are set out above in paragraphs 2.1–2.7.

3.8 Based on the information available to it, the Authority concurs with the system operator's findings that Meridian was the causer of the second UFE of 2 March 2017 at 11.24 am. The Authority's draft determination and reasons are set out above in paragraphs 2.8–2.10.

Q1. Do you agree with the Authority's draft determination that Transpower, as the grid owner that owns the Clyde-Twizel 200 kV transmission circuits, was the causer of the first UFE on 2 March 2017? If not, please state your alternative view on the causer and give your reasons.

Q2. Do you agree with the Authority's draft determination that Meridian, as a generator, was the causer of the second UFE on 2 March 2017? If not, please state your alternative view on the causer and give your reasons.

4 The Authority will consider submissions and make a final determination

4.1 Clause 8.61(4) of the Code requires the Authority to consult every generator, grid owner, and other participant substantially affected by an UFE in relation to the draft determination.

4.2 The Authority has allowed a consultation period of six weeks for these draft determinations.[4] Accordingly, the deadline for submissions is 5 pm on 28 November 2017.

4.3 The Authority will consider submissions received, and publish its final determination.

4.4 Clauses 8.62 and 8.63 of the Code set out provisions relating to any disputes regarding Authority determinations.

5 The system operator has calculated the MW lost during the UFE based on its investigations

5.1 Clause 8.64 of the Code prescribes how the system operator must calculate the event charge payable by the causer of an UFE. This in turn enables calculation of the rebates paid for UFEs (clause 8.65 of the Code).

5.2 Determining the 'MW lost' as a result of the UFE is central to the event charge calculation.

5.3 The system operator determines the MW lost as part of its investigations into an UFE.

5.4 The system operator has followed its published procedure *PR-RR-017 Calculating the Amount of MW lost* to determine the MW value provided to the clearing manager for the purposes of calculating the UFE charge. This procedure includes a factor of 95 % applied to the MW lost value to account for any margin of error.

5.5 Based on the information provided by the system operator, the Authority considers the following table sets out the system operator's intended calculations.

4 For further information about the Authority's approach to setting consultation periods for draft determinations, see the consultation paper - *Draft determination of who caused the 8 September 2016 under-frequency event* dated 14 February 2017 at http://www.ea.govt.nz/development/work-programme/risk-management/determinations-of-who-caused-under-frequency-events/consultations/#c16347.

Table 1: Expected event charges and calculations

UFE	MW lost (A)	A x .95 = B	B – 60 MW = C	C x $1250 = D
First	185.8 MW[5]	176.51 MW	116.51 MW	$145,637.50
Second	60.4 MW	57.38 MW	-2.62 MW	$0

5.6 The system operator's calculation of the MW lost during the UFE for the purposes of calculating the UFE charge is included in its report. Note this calculation does not form part of the Authority's draft determinations (refer clause 8.61). However, the Authority acknowledges that the calculation is central to determining the UFE charge payable by the causer, and therefore also to the rebates paid for UFEs.

5.7 Accordingly, the Authority invites comment on the system operator's calculation of the MW lost, as set out in the system operator's report to the Authority.

Q3. Do you agree with the system operator's calculation that, for the purposes of calculating the UFE charge, 185.8 MW was lost at the North Island HVDC injection point as a result of the first UFE on 2 March 2017? If not, please state your alternative view on the MW lost and give your reasons.

Q4. Do you agree with the system operator's calculation that, for the purposes of calculating the UFE charge, 60.4 MW was lost at the Aviemore grid injection point as a result of the second UFE on 2 March 2017? If not, please state your alternative view on the MW lost and give your reasons.

5 Paragraph 42 of the system operator's report concludes that 185.5 MW was lost. However, subsequent correspondence with the system operator on 25 August 2017 has confirmed that 185.8 MW is the actual number of MW lost. This aligns with the amount set out in the system operator's letter to the grid owner dated 6 April 2017.

Appendix A Format for submissions

Submitter	

Question		Comment
Q1.	Do you agree with the Authority's draft determination that Transpower, as the grid owner that owns the Clyde-Twizel 200 kV transmission circuits, was the causer of the first UFE on 2 March 2017? If not, please state your alternative view on the causer and give your reasons.	
Q2.	Do you agree with the Authority's draft determination that Meridian, as a generator, was the causer of the second UFE on 2 March 2017? If not, please state your alternative view on the causer and give your reasons.	
Q3.	Do you agree with the system operator's calculation that, for the purposes of calculating the UFE charge, 185.8 MW was lost at the North Island HVDC injection point as a result of the first UFE on 2 March 2017? If not, please state your alternative view on the MW lost and give your reasons.	

Q4.	Do you agree with the system operator's calculation that, for the purposes of calculating the UFE charge, 60.4 MW was lost at the Aviemore grid injection point as a result of the second UFE on 2 March 2017? If not, please state your alternative view on the MW lost and give your reasons.	

Appendix B Under Frequency Event Causation Report

Appendix C Code definitions of causer and under-frequency event

causer, in relation to an **under-frequency event**, means—

(a) if the **under-frequency event** is caused by an interruption or reduction of **electricity** from a single **generator's** or **grid owner's asset** or **assets**, the **generator** or **grid owner**; unless—

(i) the **under-frequency event** is caused by an interruption or reduction of **electricity** from a single **generator's asset** or **assets** but another **generator's** or a **grid owner's** act or omission or property causes the interruption or reduction of **electricity**, in which case the other **generator** or the **grid owner** is the **causer**; or

(ii) the **under-frequency event** is caused by an interruption or reduction of **electricity** from a single **grid owner's asset** or **assets** but a **generator's** or another **grid owner's** act or omission or property causes the interruption or reduction of **electricity**, in which case the **generator** or other **grid owner** is the **causer**; or

(b) if the **under-frequency event** is caused by more than 1 interruption or reduction of **electricity**, the **generator** or **grid owner** who, in accordance with paragraph (a), would be the **causer** of the **under-frequency event** if it had been caused by the first in time of the interruption or reduction of **electricity**; but

(c) if an interruption or reduction of **electricity** occurs in order to comply with this Code, the interruption or reduction of **electricity** must be disregarded for the purposes of determining the **causer** of the **under-frequency event**

under-frequency event means—

(a) an interruption or reduction of **electricity** injected into the **grid**; or

(b) an interruption or reduction of **electricity** injected from the **HVDC link** into the South Island **HVDC injection point** or the North Island **HVDC injection point**—

if there is, within any 60 second period, an aggregate loss of **injection** of **electricity** in excess of 60 **MW** (being the aggregate of the net reductions in the **injection** of **electricity** (expressed in **MW**) experienced at **grid injection points** and **HVDC injection points** by reason of paragraph (a) or (b)), and such loss causes the frequency on the **grid** (or any part of the **grid**) to fall below 49.25 Hz (as determined by **system operator** frequency logging)

Appendix B The system operator's causation report on the 2 March 2017 under-frequency events

Under-Frequency Events Causation Report – 2 March 2017

System Operator events 3402 & 3403

June 2017

Keeping the energy flowing

TRANSPOWER

17 - 24

Version	Date	Change
1.0	19 June 2017	Initial draft
2.0	31 July 2017	Contextual edits following comment from EA
3.0	22 August 2017	Clarification of report

	Position	Date
Prepared By:	Scott Avery, Risk and Compliance Manager, System Operations	22 August 2017
Reviewed By:	Matthew Copland, Power Systems Group Manager	22 August 2017

IMPORTANT

Disclaimer

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3

PURPOSE

1. On Thursday 2 March 2017 two events occurred on the power system that reduced the system frequency.
2. As per clause 8.60 of the Electricity Industry Participation Code (Code), Transpower as system operator investigated these events to assist the Electricity Authority in determining causers for under-frequency events.
3. The results of this investigation report are prepared under clause 8.60(5) of the Code, provided to the Authority, and relating to each identified under-frequency event includes:

4

- Whether in Transpower's view each under-frequency event was caused by the grid owner or a generator and identifies that potential causer;
- The reasons for forming this view; and
- The information considered in reaching this view.

EXECUTIVE SUMMARY

4. On 2 March 2017 two events occurred that impacted the system frequency.

5. Firstly, at 11:21 the South Island experienced an unplanned grid reconfiguration and formed two electrical islands. This resulted in the frequency in the upper South Island falling to 47.4Hz. At this point the lowering of the frequency in the upper South Island was not accompanied by any interruption or reduction of electricity at grid injection points.

6. The automatic HVDC controls detected the reduction in frequency in the upper South Island and provided frequency response as well as transferred procured reserves from the North Island. The HVDC response, transfer of reserves from the North Island, and the operation of the AUFLS scheme in the upper South Island arrested the fall in the frequency.

7. The frequency response of the HVDC link and the effect of the reserves being transferred reduced the frequency of the North Island to 49.17Hz. This reduction of the frequency was accompanied by an interruption or reduction of electricity into the North Island at the Haywards HVDC injection point and constituted an under-frequency event. This event is referred to in this report as the first under-frequency event.

8. Secondly, at 11:26 a reduction of generation from the Aviemore generator through the Aviemore grid injection point into the upper South Island grid reduced the frequency to 48.52Hz.

9. Corrective action by Aviemore generator and the governor response from other connected generators returned the frequency to the normal band. This event is referred to as the second under-frequency event.

10. In relation to the first under-frequency event the system operator recommends that no causer be identified due to the actions of the HVDC link being undertaken in order to comply with the Code, and once disregarded, no other under-frequency event exists under the Code for which to identify a causer.

11. In relation to the second under-frequency event the system operator recommends Meridian Energy as the causer.

SEQUENCE OF EVENTS

1. On Thursday 2 March 2017 at 11:21 hours, during a planned outage of a transmission circuit in the lower South Island, two other transmission circuits disconnected. This disconnection split the South Island into two separate electrical islands – effectively an unplanned grid reconfiguration.
2. From investigation into the circumstances of 2 March 2017, Transpower as system operator has identified two separate under-frequency events.

FIRST UNDER FREQUENCY EVENT CIRCUMSTANCES

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3. Normally three circuits connect the upper and lower South Island, one between Livingston and Naseby and two between Clyde and Twizel.
4. During a planned outage of the Livingston-Naseby circuit, the upper and lower South Island remained connected by the two Clyde-Twizel 220 kV transmission circuits. At 11:21 both transmission circuits were disconnected from the grid in quick succession. Consequently, the frequency in the lower electrical island increased to 53.6 Hz and the frequency in the upper electrical island dropped 47.4 Hz. At this time the HVDC link was transferring 820 MW in a northerly direction.
5. Over-frequency reserve action and generating plant governor response reduced the frequency in the lower South Island to the normal band.
6. In the upper South Island, automatic under-frequency load shedding (AUFLS), generator governor response, HVDC response, and instantaneous reserves (spinning reserve and interruptible load) from both the North and upper South Islands acted to restore the frequency to the normal band.
7. The HVDC response was to run-back transfer north, effectively delivering the reserve response from the North Island. The run-back reduced the electricity transfer into the North Island grid at the Haywards HVDC injection point and the North Island frequency fell to 49.17. This is identified as the first event.
8. Excursion Notices were sent immediately following the event

North Island

Date	Time	Minimum Hz	Island
02-Mar-2017	11:21:36	49.173	North

Date	Time	Maximum Hz	Island
02-Mar-2017	11:21:49	50.512	North

South Island

Date	Time	Minimum Hz	Island
02-Mar-2017	11:21:36	47.397	South

Date	Time	Maximum Hz	Island
02-Mar-2017	11:21:49	50.411	South

SECOND UNDER FREQUENCY EVENT CIRCUMSTANCES

9. The disconnection of the Clyde-Twizel circuits created two electrical islands in the South Island. The combined system responses to the disconnection of the circuits restored the frequency in each electrical island immediately after the initial event.

10. Instantaneous reserve generation in the upper South Island had activated and interruptible load and AUFLS tripped. All generation in the South Island remained connected through this initial reduction in the frequency.

11. One of the connected generators in the upper South Island was Aviemore. In initially responding Aviemore increased its generation output from 203 MW (dispatched) to 222 MW. The generator performed as expected and assisted in arresting the falling frequency and returning frequency to the normal band.

12. However, unknown to the Aviemore generation controllers a parameter within the control system at Aviemore had been incorrectly set. This setting reacted once the frequency reached 47.5 Hz and changed the control mode of Aviemore's governors from power control mode to speed control mode. This caused Aviemore generation output to ramp down.

13. At 11:26, five minutes after the initial disconnection of the two Clyde-Twizel transmission circuits a reduction of generation at Aviemore station reduced the frequency in the upper South Island to 48.52 Hz. This was the second event.

14. Excursion Notices were sent immediately following the event

South Island

Date	Time	Minimum Hz	Island
02-Mar-2017	11:26:37	48.515	South

Date	Time	Maximum Hz	Island
02-Mar-2017	11:28:20	50.097	South

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FINDINGS

IDENTIFYING THE CAUSER OF AN UNDER-FREQUENCY EVENT

15. The definition of "causer" is as follows:

> **causer**, in relation to an **under-frequency event**, means—
>
> (a) if the **under-frequency event** is caused by an interruption or reduction of **electricity** from a single **generator's** or **grid owner's asset** or **assets**, the **generator** or **grid owner**; unless—
>
> (i) the **under-frequency event** is caused by an interruption or reduction of **electricity** from a single **generator's asset** or **assets** but another **generator's** or a **grid owner's** act or omission or property causes the interruption or reduction of **electricity**, in which case the other **generator** or the **grid owner** is the **causer**; or
>
> (ii) the **under-frequency event** is caused by an interruption or reduction of **electricity** from a single **grid owner's asset** or **assets** but a **generator's** or another **grid owner's** act or omission or property causes the interruption or reduction of **electricity**, in which case the **generator** or other **grid owner** is the **causer**; or
>
> (b) if the **under-frequency event** is caused by more than 1 interruption or reduction of **electricity**, the **generator** or **grid owner** who, in accordance with paragraph (a), would be the **causer** of the **under-frequency event** if it had been caused by the first in time of the interruption or reduction of **electricity**; but
>
> (c) if an interruption or reduction of **electricity** occurs in order to comply with this Code, the interruption or reduction of **electricity** must be disregarded for the purposes of determining the **causer** of the **under-frequency event**

16. This definition contemplates two types of causer, which we call the "primary causer" and the "initial causer".

17. A primary causer is a generator or grid owner from whose asset there was an interruption or reduction of electricity that caused an under-frequency event. This is the type of causer referred to in the preamble to paragraph (a) and in paragraph (b).

18. An initial causer is a generator or grid owner whose act, omission or property caused an interruption or reduction of electricity that caused an under-frequency event. This is the type of causer referred to in paragraphs (a)(i) and (a)(ii).

19. The definition of causer is expressly linked to the definition of "under-frequency event", and functionally linked as well – there can be no causer without an under-frequency event. This makes the definition of under-frequency event relevant to the proper interpretation of the definition of causer.

20. An under-frequency event is an interruption or reduction of electricity of a certain type, namely of electricity injected *into the grid at a grid injection point* or *from the HVDC link at an HVDC injection point*.

21. We consider the definition of causer to be using the words "interruption or reduction of electricity" in the same sense as the definition of under-frequency event. That is, it refers to an interruption or reduction of electricity of the same type as the definition of under-frequency event. That conclusion is reinforced by the observation that the definition of causer need not have used the words "interruption or reduction of electricity" at all. For example, it could have said "if the under-frequency event is caused by ~~an interruption or reduction of electricity from~~ a single generator's or grid owner's asset or assets…". We consider the repeated use of the words in the definition of causer to be a clear and intentional link to the definition of under-frequency event.

22. Paragraph (c) of the definition of causer is also relevant to this report. Paragraph (c) requires a Code-compliant interruption or reduction of electricity to be “disregarded for the purposes of determining the causer of the under-frequency event”. “Disregarded” means ignored completely, and not only for the purposes of determining whether the participant complying with the Code is the causer but for the purposes of determining *any* causer of the under-frequency event.

FIRST (NORTH ISLAND) EVENT

23. We consider there was no causer of the first under-frequency event.

Primary causer

24. Initial analysis identified the interruption or reduction of electricity on 2 March 2017 occurred at the North Island HVDC injection point. A Prior Notification of Causer letter was sent to the HVDC owner (Transpower) accordingly, identifying the HVDC owner as the causer of the event under paragraph (a) of the definition.

25. In its response of 16 May 2017 the HVDC owner rejected that it was the causer of the event. It cited compliance with clause 8.17 of the Code as the HVDC link transfer was modulating to maintain frequency in the South Island. That meant paragraph (c) of the definition of causer applied and the HVDC owner and the associated “interruption or reduction of electricity” must be disregarded.

26. We agreed that the HVDC owner was not the causer of the event under paragraph (a) or (b) of the definition due to the effect of paragraph (c).

27. We have considered whether Transpower as the AC grid owner was the causer of the event under paragraph (a) or (b) of the definition due to the disconnection of the Clyde-Twizel circuits.

28. For that to be the case the disconnection of the Clyde-Twizel circuits would need to be an “interruption or reduction of electricity” in the sense those words are used in the definition. We do not consider that it was because:

    (a) the disconnection was an unplanned outage and reconfiguration of the grid and not an interruption or reduction of electricity injected into the grid as a whole. Immediately after the disconnection the same amount of electrical energy was being injected into the grid, causing over-frequency in the lower South Island and under-frequency in the upper South Island; and

    (b) even if the disconnection was an interruption or reduction of electricity it did not occur at a grid injection point or HVDC injection point.

29. Accordingly, we consider there was no causer of the event under paragraph (a) or (b) of the definition.

Initial causer

30. We have considered whether Transpower as the AC grid owner was the causer of the event under paragraph (a)(ii) of the definition due to the disconnection of the Clyde-Twizel circuits.

31. If the AC grid owner was the initial causer then the HVDC owner would need to be the primary causer. However, paragraph (c) of the definition requires us to disregard the interruption or reduction of electricity from the HVDC link. That means, as far as the Code is concerned, there was no relevant interruption or reduction of electricity to be caused by anything or anybody, including the AC grid owner. Put another way, paragraph (a) does not get started in this case due to the effect of paragraph (c).

32. In addition, the HVDC owner and AC grid owner are not separate participants under the Electricity Industry Act. The only relevant participant here is Transpower. Therefore, there cannot have been “another grid owner” whose act, omission or property caused the relevant interruption or reduction of electricity, as required by paragraph (a)(ii) of the definition.

33. Accordingly, we consider there was no causer of the event under paragraph (a)(ii) of the definition.

SECOND (SOUTH ISLAND) EVENT

34. Initial analysis identified the interruption or reduction of energy on 2 March 2017 occurring at the Aviemore grid injection point. Meridian Energy is the asset owner of Aviemore station. A Prior Notification of Causer letter was sent to Meridian, identifying the HVDC owner as the causer of the event under paragraph (a) of the definition.

35. In its response of 20 April 2017 Meridian Energy accepted that it was the causer of the second under-frequency event.

36. No other asset was identified as having caused or potentially caused the under-frequency event.

37. Transpower as the system operator therefore recommends that Meridian Energy is the causer of the second (South Island) event on 2 March 2017.

CALCULATION OF MW LOST

38. The purpose of this calculation is to determine the MW value provided to the clearing manager for the purposes of calculating the under-frequency event charge. Transpower as system operator follows procedure PR-RR-017 “Calculating the Amount of MW lost”.

39. This procedure follows the formula set out under section 8.64 of the Code for evaluating an event charge.

> The **event charge** payable by the **causer** of an **under-frequency event** (referred to as “Event e” below) must be calculated in accordance with the following formula:
>
> EC = ECR * (∑y (INTye for all y) – INJd)
>
> where
>
> EC is the **event charge** payable by the causer
>
> ECR is $1,250 per **MW**
>
> INJd is 60**MW**
>
> INTye is the electric power (expressed in **MW**) lost at point y by reason of Event e (being the net reduction in the **injection** of **electricity** (expressed in **MW**) experienced at point Y by reason of Event e) excluding any loss at point y by reason of secondary Event e
>
> y is a **point of connection** or the **HVDC injection point** at which the **injection** of **electricity** was interrupted or reduced by reason Event e

40. As the ECR and INJd values are constants the values to calculate and complete the formula are Y and INTye.

CALCULATION FOR FIRST (NORTH ISLAND) EVENT

41. If the interruption or reduction of electricity associated with this under-frequency event was the MW lost through the Haywards HVDC injection point into the North Island.

42. To establish the amount of MW lost, SCADA data was extracted for the 60 seconds prior to the frequency reaching 49.25 Hz for generation transfer through the North Island HVDC grid injection point. After evaluation, the amount of MW lost causing the frequency to fall below 49.25 Hz was determined to be 185.5 MW.

43. A factor of 0.95 is applied to the MW lost, 185.5 MW, to account for any margin of error, reducing the MW lost value to 176.2 MW. Subtracting 60 MW from this value yields 116.2 MW. Multiplying this figure by the ECR gives an event charge of $145,281.

44. Note that due to an error in the calculation applied in the Prior Notification of Causer letter to Transpower as the grid owner[1], this calculated value differs from that value.

45. In response to the letter received from the grid owner[2] the system operator agreed that the reduction of electricity by the HVDC occurred in order to comply with clause 8.17 of the Code and not the causer.

46. It should be noted that once disregarded, there is no longer a MW lost value that can be used as part of the calculation as prescribed under clause 8.64.

CALCULATION FOR THE SECOND (SOUTH ISLAND) EVENT

47. The fall in frequency to 47.5 Hz in the upper South Island triggered a change in Aviemore station's control system. This change prompted the station to run back generation output. The generation is injected at Aviemore grid injection point (GIP).

48. To establish the amount of MW lost, SCADA data was extracted for the 60 seconds prior to the frequency reaching 49.25 Hz for generation at the Aviemore grid injection point. After evaluation, the amount of MW lost causing the frequency to fall below 49.25 Hz was determined to be 60.4 MW.

49. In this event the slow ramp down of Aviemore generation, combined with the lack of instantaneous reserves which had already fired, meant that frequency slowly declined over the course of several minutes.

50. A factor of 0.95 is applied to the MW lost value to account for any margin of error, reducing the MW lost value to 57.4 MW. Subtracting the 60 MW from this value yields a negative value, and an event charge of zero.

51. Note that due to an error in the calculation applied in the Prior Notification of Causer letter to Meridian[3], this calculated value differs from that value.

[1] Letter dated 6 April 2017, appendix 1.3

[2] Letter dated 16 May 2017, appendix 2.1

[3] Letter dated 6 April 2017, appendix 1.6

Appendix 1: SYSTEM OPERATOR CORRESPONDENCE

1.1 CONFIRMATION OF EVENT NOTICE – FIRST EVENT

TRANSPOWER SYSTEM OPERATOR

Date: 8 March 2017

To: Market Participants
cc: Clearing Manager
From: System Operator

Under-frequency Event Confirmation

The System Operator wishes to advise market participants of the under-frequency event which occurred in both the North Island and South Island on 02 March 2017.

Event ID:	114
Affected Islands:	North Island and South Island
North Island Minimum Frequency:	49.17 Hz
Time (of min. frequency):	11:21:36
South Island Minimum Frequency:	47.40 Hz
Time (of min. Frequency):	11:21:36

Transpower New Zealand Ltd The National Grid

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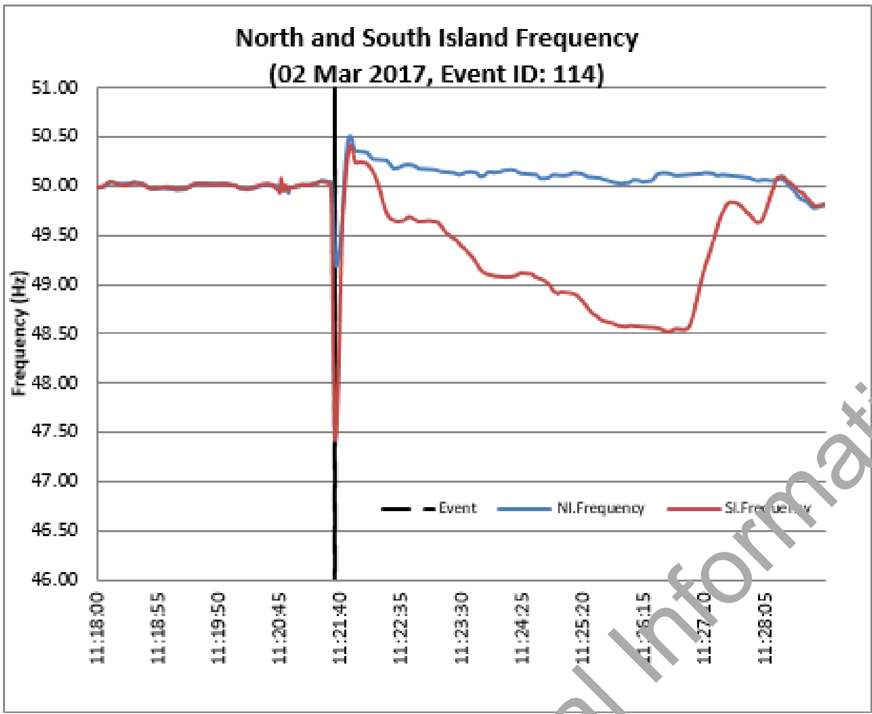


Market Operations
Transpower NZ Ltd
P.O. Box 1021.
Wellington,
New Zealand

Telephone: 04 590 7470

1.2 CONFIRMATION OF EVENT NOTICE – SECOND EVENT

TRANSPOWER | SYSTEM OPERATOR

Date:	8 March 2017
To:	Market Participants
cc:	Clearing Manager
From:	System Operator

Under-frequency Event Confirmation

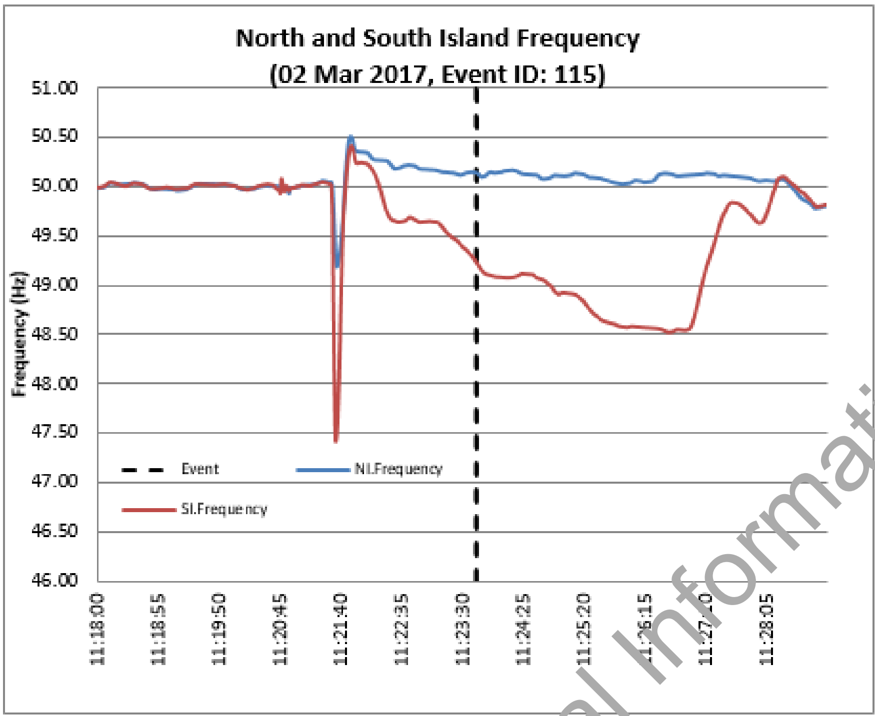
The System Operator wishes to advise market participants of the under-frequency event which occurred in both the North Island and South Island on 02 March 2017.

Event ID:	115
Affected Islands:	South Island
North Island Minimum Frequency:	50.13 Hz
Time (of min. frequency):	11:25:55
South Island Minimum Frequency:	48.52 Hz
Time (of min. Frequency):	11:26:37

Transpower New Zealand Ltd The National Grid

15

16



Market Operations
Transpower NZ Ltd
P.O. Box 1021.
Wellington,
New Zealand

Telephone: 04 590 7470

1.3 PRIOR NOTIFICATION OF CAUSER – FIRST EVENT

TRANSPOWER

Transpower House
96 The Terrace
PO Box 1021
Wellington 6140
New Zealand
P 64 4 495 7000
F 64 4 495 7100
www.transpower.co.nz

Scott Avery
Tel: (04) 590 6144
Mob: 027 7065164

6 April 2017

Kent Murrell
Transpower NZ Ltd
PO Box 17188
Wellington

Dear Kent

Under frequency event 2 March 2017

On 2 March 2017, an under-frequency event occurred in the North Island at 11:21. Based on the information available we believe that the event was potentially caused by the HVDC Link.

In order to report to the Electricity Authority as required by clause 8.60 of the Electricity Industry Participation Code we would appreciate any information you can provide around this event, and whether you believe Transpower New Zealand (as Grid Owner) is the causer of the under-frequency event.

From our assessment of the event at time the frequency reached 49.25Hz in the North Island the HVDC transfer was at 603.82MW (11:21:36). 60 seconds prior to this the HVDC transfer was 789.64MW.

Time	HVDC MW	North Island Frequency
02-Mar-17 11:20:36	789.64	50.00
02-Mar-17 11:21:36	603.82	49.23

This indicates that the reduction of 185.8MW of HVDC transfer was the MW lost which caused the event. Using this figure of MW lost the event fee would likely be ((185.8-60)*.95)*$1250 = $149,420.

If you have a view on the amount of electricity lost during this event please include that information in your response.

After receipt of your information Transpower (as the system operator) will prepare and send a report to the Electricity Authority with our view on whether the under-frequency was caused by a generator or grid owner, the identity of the causer, the reasons for our view and all of the information considering in reaching our view.

Please respond to the system operator with your information relating to this event no later than 5 May 2017.

Regards,

Scott Avery
Risk and Compliance Manager

CC Dean Eagle (System Operator)

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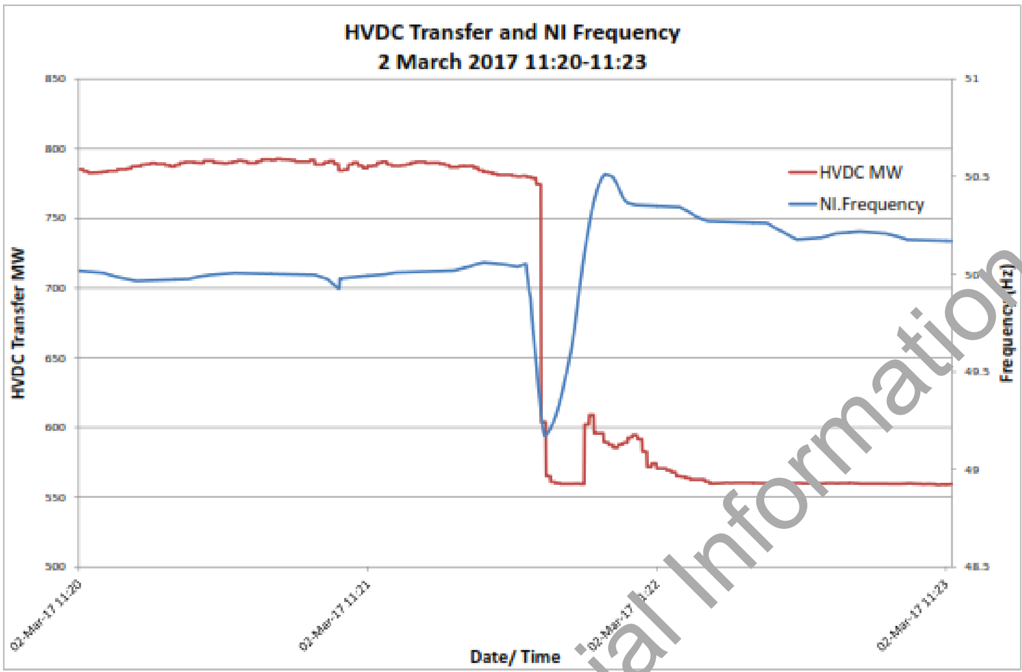

HVDC Transfer and NI Frequency
2 March 2017 11:20-11:23
HVDC MW
NI.Frequency
HVDC Transfer MW
Frequency (Hz)
Date/ Time
02-Mar-17 11:20
02-Mar-17 11:21
02-Mar-17 11:22
02-Mar-17 11:23
850
800
750
700
650
600
550
500
51
50.5
50
49.5
49
48.5

1.4 PRIOR NOTIFICATION OF CAUSER – SECOND EVENT

TRANSPOWER

Scott Avery
Tel: (04) 590 6144
Mob: 027 7065164

Transpower House
96 The Terrace
PO Box 1021
Wellington 6140
New Zealand
P 64 4 495 7000
F 64 4 495 7100
www.transpower.co.nz

6 April 2017

Simone O'Loughlin
Meridian Energy Ltd
287 – 293 Durham Street
PO Box 2146
Christchurch

Dear Simone

Under frequency event 2 March 2017

On 2 March 2017, an under-frequency event occurred in the South Island at 11:23. Based on the information available we believe that this event was potentially caused by the Aviemore Power Station.

In order to report to the Electricity Authority as required by clause 8.60 of the Electricity Industry Participation Code we would appreciate any information you can provide around this event, and whether you believe Meridian Energy is the causer of this under frequency event.

We have also calculated the loss of injection of electricity to the grid for the event as 60.4MW.

Time	AVI Generation	SI Frequency
02-Mar-17 11:22:42	173.40	49.68
02-Mar-17 11:23:42	113.00	49.249

From our assessment of the event at time the frequency reached 49.25Hz in the South Island the generation at Aviemore was 113.0 MW (11:23:42). 60 seconds prior to this the generation was 173.4 MW.

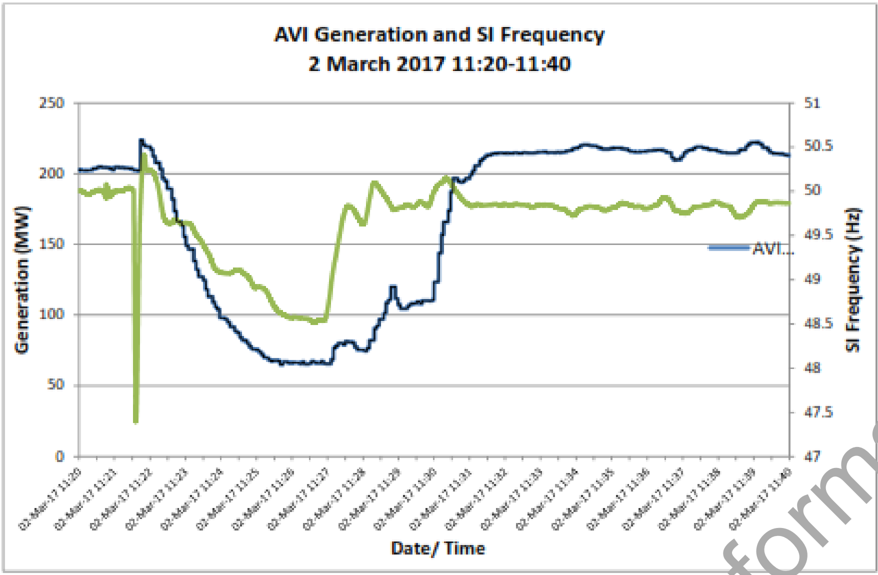
This indicates that the reduction of 60.4 MW of generation at Aviemore was the MW lost which caused the event. Using this figure of MW lost the event fee would likely be

((60.4-60) *0.95) * $1250 = $475

If you have a view on the amount of electricity lost during this event please include that information in your response.

After receipt of your information the Transpower (as system operator) will prepare and send a report to the Electricity Authority with our view on whether the under-frequency was caused by a generator or grid owner, the identity of the causer, the reasons for our view and all of the information considering in reaching our view.

Keeping the energy flowing Transpower New Zealand Ltd The National Grid



Please respond to Transpower (as system operator) with your information relating to this event no later than 28 April 2017.

Regards,

Scott Avery
Audit and Compliance Manager

CC Dean Eagle (System Operator)

Appendix 2: RECEIVED CORRESPONDENCE

2.1 TRANSPOWER RESPONSE TO FIRST EVENT

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TRANSPOWER
Keeping the energy flowing

Transpower House
96 The Terrace
PO Box 1021
Wellington 6140
New Zealand
P 64 4 495 7000
F 64 4 495 7100
www.transpower.co.nz

Kent Murrell
Tel: (04) 590 6924
DX: SR 56017

16 May 2017

Scot Avery
Risk and Compliance Manager
Transpower New Zealand Limited
P O Box 1021
Wellington

Dear Scott

Thank you for your letter of 06 April 2017 regarding the under-frequency event that occurred at 11:21 on 02 March 2017 in the North Island. The following is in answer to your questions:

Prior to the event that occurred in the South Island on 02 March 2017, the HVDC was running in Frequency Keeping Control mode. When the South Island was split into two separate islands at 11:21, the HVDC transfer into the North Island was reduced by about 236MW to arrest the frequency fall in the upper South Island. This reduction in North transfer resulted in the North Island frequency falling to 49.17Hz.

Clause 8.17 of the EIPC states that *"the HVDC owner must at all times ensure that its assets make the maximum possible injection contribution to maintain frequency within the normal band (and to restore frequency to the normal band)"*. The reduction in North transfer by the HVDC to arrest the falling frequency in the upper South Island was as expected and in accordance with this requirement of the Code.

Clause 1.1 of the EIPC states that *"if an interruption or reduction of electricity occurs in order to comply with this Code, the interruption or reduction of electricity must be disregarded for the purposes of determining the causer of the under-frequency event."* As the response of the HVDC was in order to comply with Clause 8.17 of the Code, the Grid Owner does not accept that is was the causer of the under-frequency event that occurred at 11:21 on 02 March in the North Island.

The Grid Owner agrees that the reduction of electricity into the North Island by the HVDC for this event was 185.5 MW as advised by the System Operator.

If you require any further information, please contact me on 04 590 6924 or e-mail me on kent.murell@transpower.co.nz.

Yours sincerely

Kent Murrell

Kent Murrell
Grid Compliance Manager

Transpower New Zealand Ltd The National Grid

2.2 MERIDIAN ENERGY RESPONSE TO SECOND EVENT

Hi Scott,

[redacted] Having reviewed the event on the 2nd March 2017 11:23, Meridian agrees that the second under frequency event at the time was attributed to the Aviemore generation reduction and therefore that Meridian was the causer of the second under frequency event.

Regards,

Jon Spiller
Transmission Manager
Meridian Energy Limited
33 Customhouse Quay, PO Box 10840, Wellington.
P. 04 381-1235
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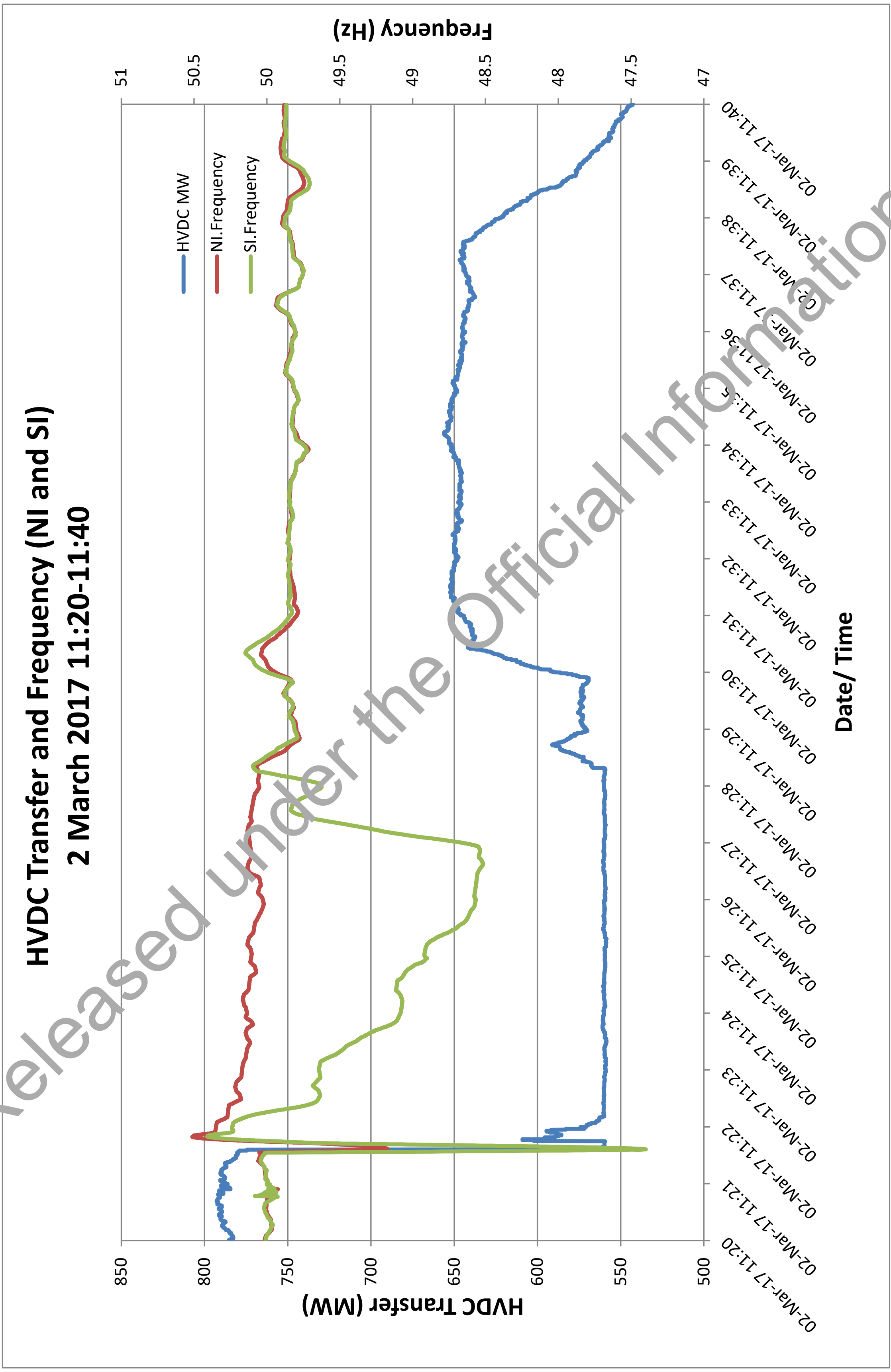
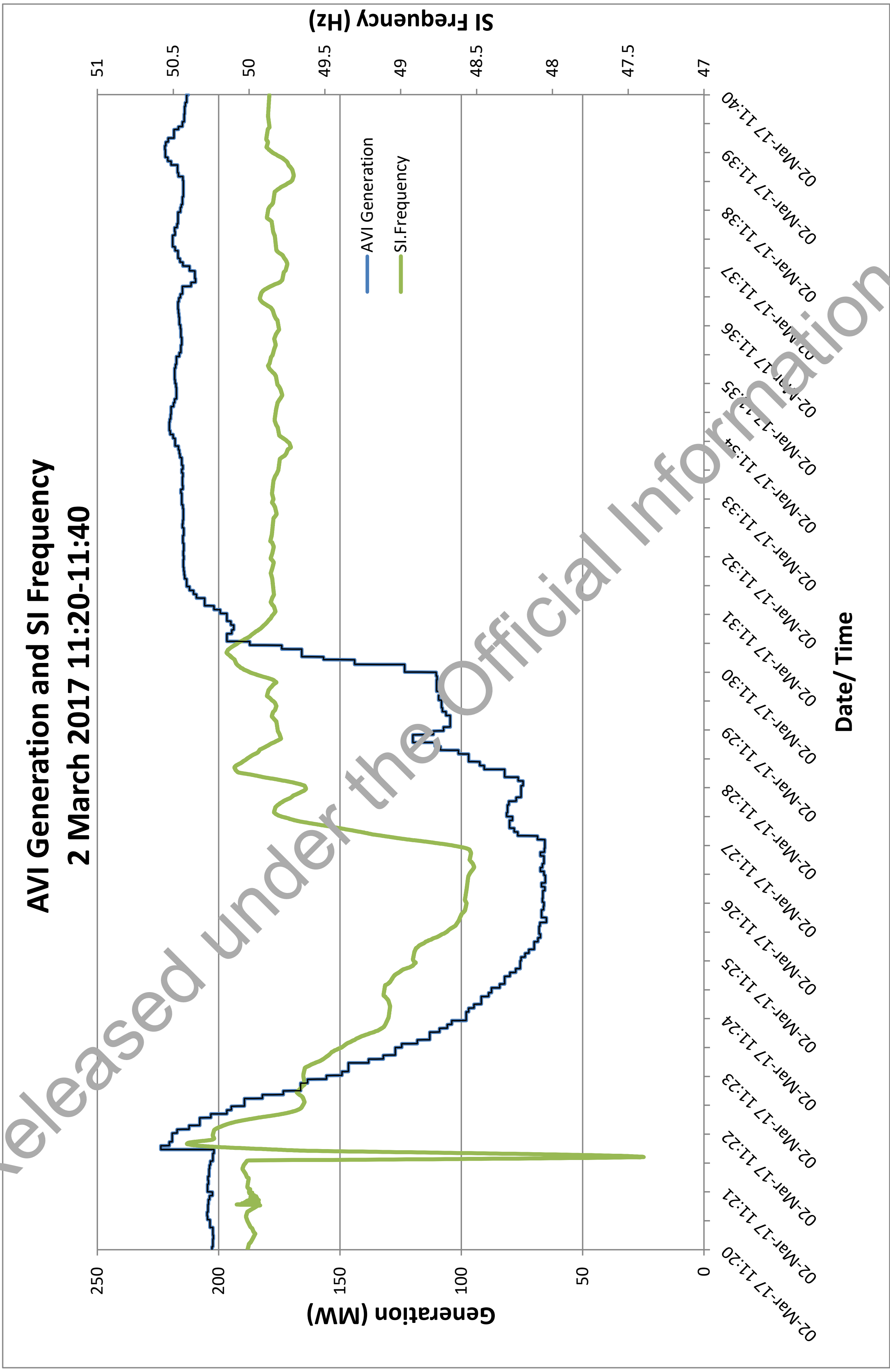
22

Appendix 3: CHARTS

3.1 ISLAND FREQUENCIES AND HVDC TRANSFER



3.2 Loss of Aviemore Generation



Appendix C Duncan Cotterill's legal opinion on the first of two under-frequency events on 2 March 2017

[redacted]

[redacted]

[redacted]

[redacted]

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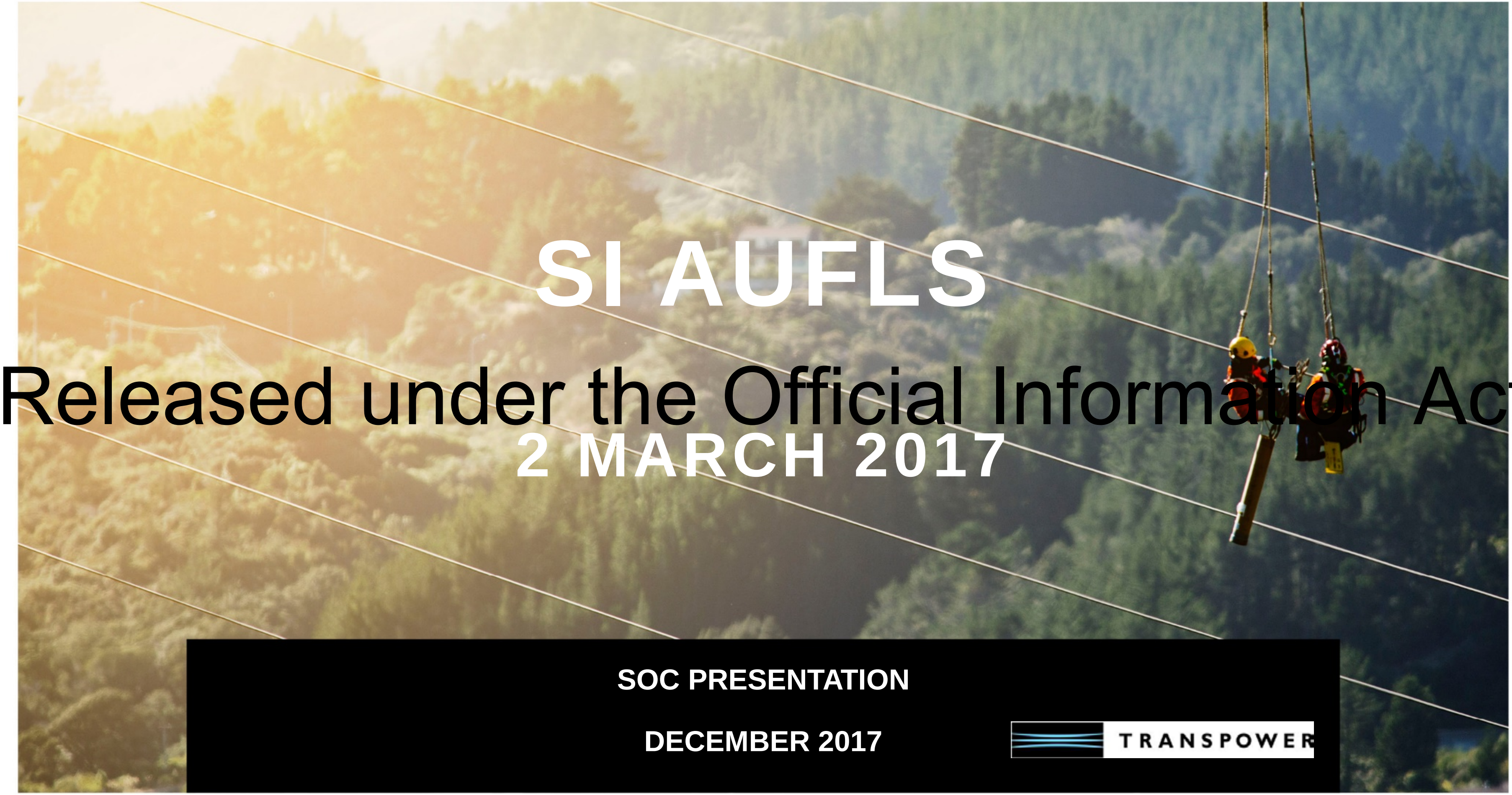
[redacted]



SI AUFLS

2 MARCH 2017

SOC PRESENTATION

DECEMBER 2017

TRANSPOWER

CONTEXT

- Process – shared all source reports with Authority staff and draft summary report. Summary report covers on two main issues. Will consider changes to our report from SoC, SRC and Authority feedback
- Authority staff have provided their views and draft recommendations to SoC and SRC. Transpower has not had the opportunity to formally respond. Concerns about the views expressed. Some responses in this presentation
- Event - two major electrical islands, an AUFLS event and an IL event, all at once

- SO security risk management controls worked effectively – 23 mins to re-synchronisation; 90 mins to complete restoration, Recovery quick; interruption to consumers limited
- However, our failure to correctly use AutoSync created a material risk; has already been largely addressed
- This presentation and discussion has a focus on the system operator service.

PURPOSE OF REPORT

- Summarise investigation findings and corrective actions
- Investigation methodology
- Three principle areas of investigation:-
  - Disconnection of two circuits during planned maintenance, creating 2 islands
  - System response – operation of AUFLS, Over Frequency Arming, HVDC Frequency keeping and Interruptible Load
  - Restoration – synchronising of two islands and load restoration
- Using the standard TP ICAM approach
- TP immediate, self-generated reviews to enable quick fixes
- Two expert independent investigators covering complex areas.

DISCONNECTION

DISCONNECTION

Direct cause

- Failure at job planning stage to identify the existence of a bus zone initiated intertrip and its interconnection with the equipment under test (CB fail bus zone timers); resulted in failure to isolate protection scheme for maintenance activities.

Contributing causes

- Design difficult to isolate and maintain
- Drawings didn't identify complexity/interlinkage between intertrip and CB fail timers
- Work statements were in place, but expectation gap between designers/TP protection engineers and technicians as to amount of searching for isolation required
- There is limited situational awareness for technicians (mimic boards, station alarms and operators no longer present).

Relevant to system operator

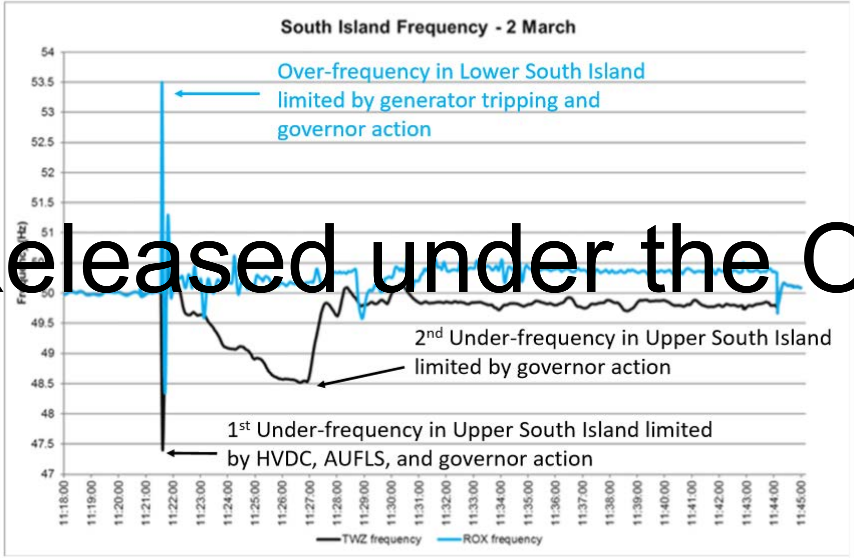
During outage planning, the risk to the system not assessed as being higher than other similar work previously undertaken. Event exposed a flaw in our outage planning process.

SYSTEM RESPONSE

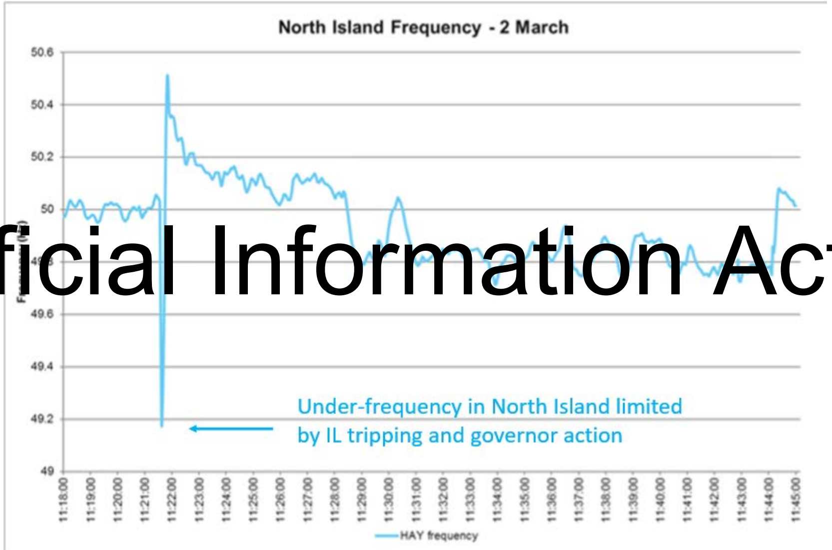
EVENT SUMMARY

SIAUFLS – 2 March 2017

Frequency Fluctuations
Upper and Lower South Island



Frequency Fluctuations
North Island



AUFLS OPERATION


RESTORATION

RESTORATION

- System Co-ordinators took immediate action to stabilise system
- Aviemore ramped down shortly after event
- Other operational responses influenced restoration:
  - very high NCC and NGOC workloads
  - generators were off set point and TKA was stuck in island mode
  - HVDC dispatch was complex – a priority action to re-dispatch
  - CYD_CML_TWZ lines not removed from offer; allowed re-livening despite fault source not being known
- Grid Emergency declared at 11:28, 8 minutes into event
- Decision made to re-synchronise rather than pursue remodelling and economic dispatch
- Islands reconnected through incorrect use of AutoSync

ELECTRICITY AUTHORITY CONCERNS

AUTHORITY CONCERN 1

NCC failed to obtain operational protection advice

- Grid owner regularly takes engineering advice in relation to restoration activities (e.g. duty protection advisors)
- Grid owner did seek protection advice during this event; was not received prior to re-livening.

AUTHORITY CONCERN 2

Frontline staff didn't know how to use AutoSync tool

- AutoSync not previously used operationally
- Installed 2 years previously, with paper-based training now recognised as insufficient
- Procedure document – if followed – should have led to proper synchronisation.

AUTHORITY CONCERN 3

Incorrect dispatch instructions sent post event

- SPD struggled to issue suitable dispatch instructions (CYD_TWZ circuits not offered out)
- Energy co-ordinators concentrated on HVDC dispatch – key element in restoration
- Re-modelling to get 'proper' SPD dispatch complex and time consuming manual task, with attendant risks
- NCC knew dispatch instructions (especially lower SI) were wrong; focus elsewhere
- NCC confident lower SI generators knew what to do even though electronic dispatch seemed.

AUTHORITY CONCERN 3

- NCC restoration actions consistent with Code Part 8 restoration priorities, which are:
    1. the safety of natural persons
    2. the avoidance of damage to assets
    3. restoration of offtake
    4. conformance with the principal performance obligations
    5. full conformance with the dispatch objective.

AUTHORITY CONCERN 4

Failure to identify cause of circuit trippings - resulting lack of situational awareness

- Tripped assets not offered out to NCC
- Were expressly (verbally) made available by NGOC during the event
- NGOC did make key safety asset checks (alarms, flags etc.)
- Not an issue of system operator situational awareness.

AUTHORITY REPORT: RECOMMENDATION A

Outage planning practices

- We accept event showed a flaw in Transpower’s outage planning process
- Improvement actions underway (slide 21/22)
- February realistic date for completion for some actions
- Further actions require cross Transpower input; uncertain completion date.

AUTHORITY REPORT: RECOMMENDATION B AND C

B: Improvement actions for dispatch during major events

C: Preparing frontline staff for rare system events.

Yet to have discussion with EA staff regarding reasoning behind recommendations

- Major event simulations a regular feature of NCC and NGOC training
- No current plans to change training approach; always incrementally improving
- This event now a training artefact
- Dispatch policy follows the Code mandated priorities.

SYSTEM OPERATOR CORRECTIVE ACTIONS

REPORT SO ACTIONS

Six New Actions – Three relate to SO Role

- Improve current outage planning processes to include a risk-based approach that assesses requests for outages of protection equipment to identify maintenance activities that have a high system impact (including the impact of other concurrent planned outages)

- Review the existing AutoSync tool and procedures to support National Grid Operating Centre (NGOC) grid asset controllers and National Co-ordination Centre (NCC) system co-ordinators working under pressure, and review if automatic systems can be added to limit the impact of incorrect operator actions

- Assess and address the training needs of NGOC and NCC staff to ensure compliance with policies and use of procedures during restoration from rare events

ACTIONS UPDATE
OUTAGE PLANNING (1)

In place or underway (complete Feb 2018)

- Quarterly SOGO meetings consider significant concurrent outages
- Requests for protection advice now generated automatically.

Further work (complete post-Feb)

Scope of further actions likely to include:

- Updating outage block information in IONS with both system operator security and grid owner protection information (this work is underway)
- Considering effect of N-2 contingencies consistent with Security Policy framework
- Identifying in IONS significant circuits and high-risk protection outages to improve risk awareness

ACTIONS UPDATE
OUTAGE PLANNING (2)

- continue determination of which outage blocks need protection advice field-set automatically (of 1000s of outage blocks.)
- working with grid owner to establish clear role accountabilities:
  - When protection testing is being carried out SO needs conformation that the grid owner has carried out a risk-based approach to that test procedure in relation to other concurrent outages.
  - SO entitled to rely on asset owner (i.e.: grid owner’s protection and automation team) to carry out that assessment and advise implications - for consideration in relation to system security.

ACTIONS UPDATE – AUTOSYNC AND TRAINING

AutoSync

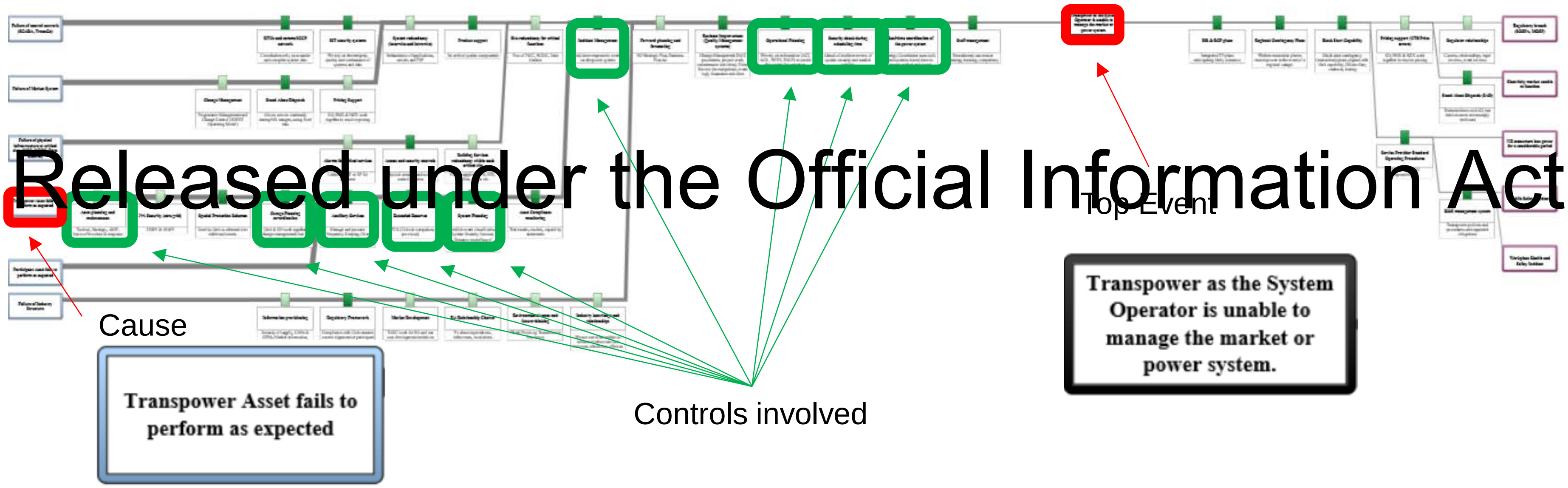
- Simulator updated to enable full replication of AutoSync screens and use of functionality during training
- Simulator training for islanding redesigned to reduce ambiguity and strengthen consideration of re-dispatch as valid option
- Approval for NGOC use of AutoSync now 'one up'

- AutoSync procedure upgraded improving usability and includes new checklist style
- Testing of AutoSync successfully completed (as a 'live' simulation) during recent Clyde black start test.

Training

- Review of training for NGOC staff, including increase of frequency
- Refer response to Authority Recommendations B and C

2 MARCH 2017



Top Event
Transpower as the System Operator is unable to manage the market or power system.
Cause
Transpower Asset fails to perform as expected
Controls involved

CONTROLS INVOLVED

Asset planning and maintenance

Ancillary Services

Extended Reserves

System Planning

Outage Planning Co-ordination

Incident Management

Operational Planning

Security check during scheduling time

Real-time coordination of the power system

UPDATED CONTROLS

Asset planning and maintenance

The SO relies on asset owners planning, designing, building testing and maintaining assets to ensure power system performance and reliability.
Assurance sought from asset owners that assets can be tested safely and will perform as required.

Outage Planning Co-ordination

The SO coordinates planned outages on the power system to ensure reliability and security.
Process improvement for and increased awareness of potential risks and impacts from protection equipment and maintenance activities.

Incident Management

The SO manages a dynamic power system through process, procedure and trained coordinators for complex and diverse events.
Clarification of processes and specific technical training for AutoSync tools and restoration procedures.

TRANSPOWER

Report on 2 March 2017 South Island AUFLS Event

June 2018

Keeping the energy flowing

TRANSPOWER

IMPORTANT

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Executive Summary

On 2 March 2017, New Zealand experienced a major and complex power system event. The event resulted in the South Island power system splitting into two separate systems. Approximately 120 MW (16%) of electricity used by consumers in the upper part of the South Island was disconnected for up to 90 minutes.

The trigger for the incident was the disconnection of two in-service 220 kV transmission circuits during scheduled equipment tests at Transpower's Clyde substation. This disconnection resulted in two separate unbalanced power systems (referred to as electrical 'islands'). Immediately on separation, the upper South Island 'island' experienced a shortage of generation and the lower South Island 'island' had an excess of generation.

Automatic controls including instantaneous reserves, HVDC response, over-frequency arming and under-frequency load shedding acted to initially stabilise the two systems. This was followed by control room operator actions to attempt to further stabilise and ultimately reconnect the two electrical islands and restore disconnected consumers.

Despite the quick recovery, there were concerns about how routine testing could have resulted in such a major event, and the way the system was attempted to be stabilised and then restored.

In the months following the event, Transpower (in its dual roles as both system operator and owner and operator of the national grid) carried out an investigation to determine what had happened; what lessons could be learned for both Transpower and the wider industry; and the actions to be taken as a result. The early focus of this investigation was on issues relating to outage planning, the event trigger and incorrect actions synchronising the two electrical systems.

Following feedback from the Electricity Authority's System Operator Committee and the Security and Reliability Council, Transpower undertook a further review of its performance in its role as system operator during the event, focusing on matters relating to dispatch, frequency keeping, system stabilisation, failure to use standard operating procedures and poor operational communications.

This report summarises the findings of these investigations and includes internal reports as well as external reports from Power Systems Consulting and BEC Consulting. Wherever possible, we have attempted to use language in this summary report that is consistent with the other reports to ensure clarity. However, since the reports and investigations were undertaken at different times and by different groups, this was not always possible.

Transpower acknowledges that the time taken to investigate and publish this report has fallen below the standard expected of us. We are committed to ensuring that future investigations and reports will be timely and thorough, with independent input and review as appropriate.

Key Findings

Key Finding 1: The event was caused by a failure to identify the recently installed intertripping equipment and therefore its effect on the work being undertaken. The failure to identify this equipment meant it was not adequately isolated from being able to send command intertrip signal(s) which opened the circuit breakers creating the two islands. The bus zone CB fail intertrip scheme was complex with drawings of a low quality. The design of isolation points was unintuitive and impractical to achieve the isolation required to allow maintenance to be carried out.

Key Finding 2: There was a lack of situational awareness by technicians working on the 220 kV protection at Clyde.

Key Finding 3: There was insufficient consideration in the outage planning process of risks associated with maintenance on 220 kV protection at Clyde during high power transfers from the Lower South Island to Upper South Island.

Key Finding 4: Our operational communications were insufficiently clear, formal or effective.

Key Finding 5: There was a lack of effective event management between the NCC and NGOC operators which impacted their situational awareness and their ability to enact restoration.

Key Finding 6: Our market system software can be difficult to remodel in real-time, following major system events. This means the software is not as useful as it could be in restoring the system following system events.

Key Finding 7: The procedures for using the Autosync tool, returning assets to service and voice communications were not followed. Operation of the Autosync tool was not well understood by either NCC or NGOC personnel.

Key Finding 8: The configuration of two distribution networks in the upper South Island reduced the effective amount of AUFLS provided

SUMMARY OF ACTIONS

Transpower has already completed a number of actions in response to these findings and has also identified a number of other actions which are either underway or have been recommended for further development. Transpower will publish an action plan and regularly report on progress until the actions are completed. The actions are summarised in the table below:

Actions	Key Finding no.	Status
1. Agree an approach, to be used in future, by protection designers and technicians, to enable access to site-specific information on protection schemes.	1, 2	On track June 2018
2. Develop a process that supports protection designers in gaining clarity on isolation, testing and maintenance requirements for future protection schemes early in the design process - allowing for appropriate consultation with protection technicians who will be undertaking the work.	1, 2	On track June 2018
3. Consider providing real-time SCADA data to technicians	1, 2	On track June 2018
4. Improve current outage planning processes to include a risk based approach that assesses requests for outages of protection equipment to identify maintenance activities that have a high system impact (including the impact of other concurrent planned outages).	3	On track June 2018
5. Review the existing Autosync tool and procedures to support NGOC grid asset controllers and NCC system co-ordinators working under pressure.	7	On track

Actions	Key Finding no.	Status
		June 2018
6. Re-emphasise and embed through regular training of NGOC and NCC staff the importance of compliance with policies and use of procedures during restoration after rare events.	5, 7	Complete
7. Review procedures across Transpower regarding handover of tools and systems to ensure the tools and systems are able to be effectively operationalised	7	Not started Dec 2018
8. Investigate improvements in the design and use of the market model and market system to assist in the management of large scale system restoration events	6	Not started Dec 2018
9. Work with industry and real-time teams within Transpower to address issues with operational communications	4, 5	On Track Dec 2018
10. Work with generators to assess what real-time information could assist them with visibility of the system during events and investigate the practicability of providing this.	5	On track Dec 2018

CONTENTS

1 Context and Details of the Event

1.1 What Does This Report Cover?

This report presents the findings of Transpower's investigation into the 2 March 2017 South Island AUFLS event, undertaken by Transpower in its capacity as both grid owner and system operator[1]. This report considers issues relating to testing of critical control schemes (used to protect equipment from damage and overloading) as well as the operation and restoration of the power system from Transpower's control centres. This report is informed by several reports including:

- the Preliminary System Operator Report into this event, issued in March 2017 with minor updates in November 2017, which explains technical aspects of this event (Appendix B);
- a Power Systems Consulting (PSC) report on the system and asset impacts of the event (Appendix C);
- a BEC Consulting report looking at the actions of the technicians performing the testing at Clyde (Appendix D);
- discussions with Meridian Energy ('Meridian') and Contact Energy ('Contact') staff and management;
- feedback from Electricity Authority staff, management and the System Operator Committee of the Electricity Authority Board;
- feedback from the Security and Reliability Council.

This report excludes consideration of any Electricity Industry Participation Code breaches arising from this event. These are being dealt with as part of a separate compliance investigation by the Electricity Authority.

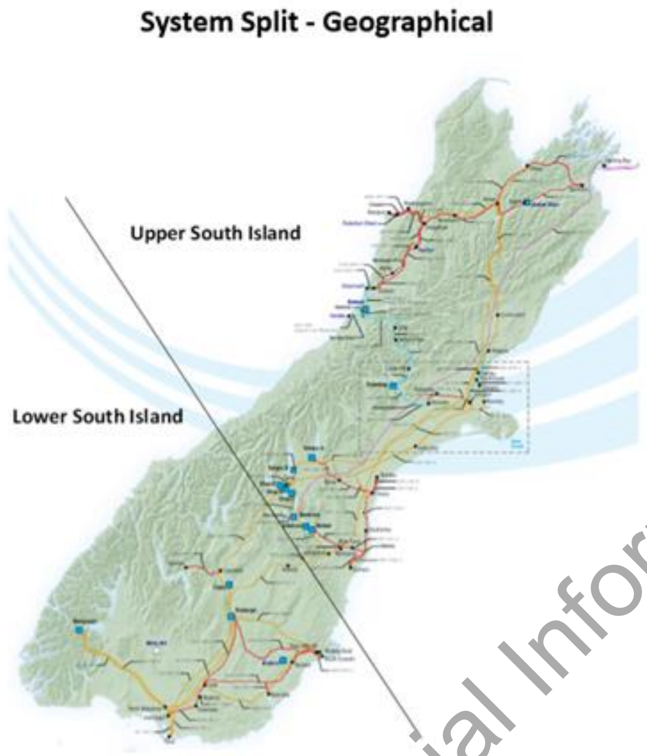
1.2 Description of Event

On 2 March 2017 at 11:20:45, during planned eight-yearly maintenance on the Clyde 220kV busbar and circuit breaker fail protection schemes, an intertrip signal was inadvertently sent to Twizel to open the circuit breakers at the Twizel end of the Clyde–Cromwell-Twizel-2 220kV circuit. At 11:21:32, 46 seconds later, the sequence was repeated for the Clyde-Cromwell-Twizel-1 220 kV circuit. At the time, the Livingston-Naseby-1 220kV circuit was out of service for hardware replacement work.

The sequential loss of two transmission circuits is not normally managed as an expected power system risk. This particular set of circumstances led to a rare, significant and highly complex power system event - the creation of two electrical islands within the South Island power system (one including Waitaki Valley and the upper South Island and the other including Clutha Valley and the lower South Island).

[1] Transpower has two operational roles in managing the power system and grid in real- time. These duties are performed by teams in the National Co-ordination Centre (NCC) and the National Grid Operating Centre (NGOC). NCC coordinates operation of the power system between generators, ancillary service agents, NGOCs and distribution company control rooms. NGOC is responsible for managing the switching and control of Transpower's national grid equipment.

Figure 1: Geographical representation of two electrical islands formed by the event



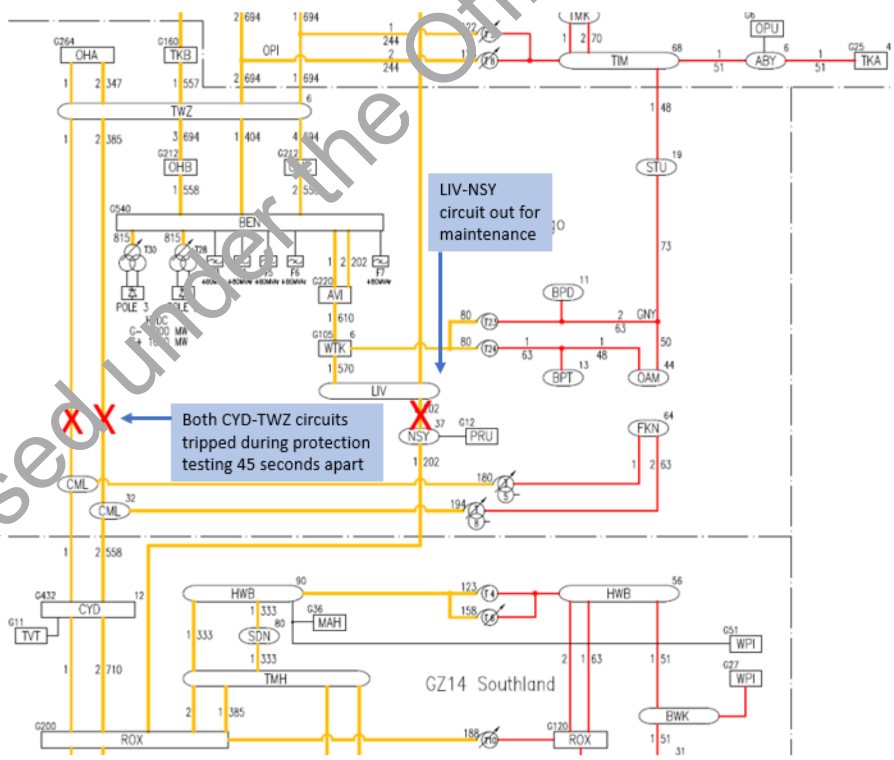


Figure 2: Single line diagram showing LIV-NSY circuit out of service for maintenance and CYD-TWZ circuits which tripped during the event.

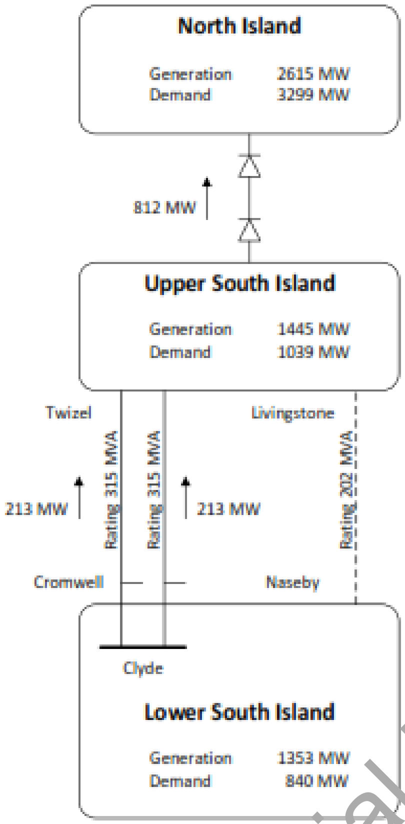


Figure 3: Three island representation of system split.

Four control systems acted immediately to assist in stabilising the system imbalance.

- *High Voltage Direct Current Frequency Keeper Control (HVDC FKC):* FKC ties the North and South Island frequencies together by continuously changing the levels of HVDC transfer. FKC can operate within a +/- 250 MW band around the HVDC dispatch set point. In this event, the response from the HVDC FKC reduced its transfer north by 250 MW. This reduction prevented a further fall in frequency in the upper South Island, though also triggered the activation of contracted under-frequency reserves in the North Island.
- *Under-frequency reserves:* The reduced transfer of electricity into the North Island following the drop in power system frequency in the upper South Island resulted in an under-frequency event where contracted interruptible load was disconnected in the North Island. Under-frequency reserves in the upper South Island also responded.
- *AUFLS:* The size of the drop in frequency triggered the South Island AUFLS scheme, which is enabled at all times to cover an extended contingent event, such as loss of the HVDC bi-pole when there is high south flow or loss of a major South Island generating station. The AUFLS system acts as a 'safety net', reducing defined portions of load across the network to prevent further outages. The activation of AUFLS resulted in the unplanned disconnection of 16% of consumer demand (120 MW) in the upper South Island.
- *Over Frequency Reserve:* Over Frequency Reserve (OFR) was armed on selected South Island generators, to manage the loss of the HVDC bi-pole due to the high north flow at the time. The increase in power system frequency in the lower South Island resulted in three generating units being disconnected.

This automated response occurred in the first few seconds after separation of the South Island power system into two islands, and acted to initially stabilise the lower South Island and upper South Island systems. The response was sufficient for both islands to survive the disturbance and prevented a far wider loss of supply.

Immediately after the event, Transpower's system co-ordinators (NCC) and grid asset controllers (NGOC) attempted to further stabilise the power system, and then reconnect the two islands and restore disconnected consumers. Although this stabilisation and restoration was ultimately effective, the way in which it was managed raised concerns about Transpower's management of the event.

A timeline of the event is set out below. *Note: This timeline is intended to provide a summary of the timing of events and does not comment on the sufficiency of any actions taken - this is covered elsewhere in the report.*

11:20	Clyde-Cromwell-Twizel 2 (CYD_CML_TWZ_2) circuit tripped at Twizel. Forty seconds later, the parallel Clyde-Cromwell-Twizel 1 (CYD_CML_TWZ_1) circuit tripped, disconnecting the lower South Island from the upper South Island.
11:21	Disconnecting generation from load caused system frequency to drop in the upper South Island to 47.4 Hz and to rise in the lower South Island to 53.6 Hz. The HVDC FKC control reacted to the low frequency in the upper South Island by reducing HVDC transfer north to 576 MW (from 826 MW dispatched). The reduction resulted in a fall of North Island frequency to just below 49.2 Hz. As a result of the circuit tripping and HVDC run-back, contracted reserve generation and interruptible load triggered in both the upper South Island and North Island, including 16% of upper South Island load controlled under automatic under-frequency load shedding (AUFLS, approximately 120 MW). 336 MW of North Island interruptible load tripped in response to the North Island under-frequency event. Generators in the lower South Island either tripped (from operation of Over Frequency Reserve relays) or ramped down output in response to rapidly increasing system frequency. Generation from Aviemore power station began to decrease in response to the low frequency in the upper South Island.
11:28	The status of the power system at this time can be summarised as: • The power system had split in the South Island • Lower South Island was largely stabilised • Upper South Island frequency had continued to fall post the system split (the runback of Aviemore generation) and remained under the normal band • North Island had experienced an under-frequency event, island was stable but instantaneous reserves had triggered and were not available for any subsequent event • HVDC link was at minimum modulation and energy co-ordinators were unable to re-dispatch, cause unknown • The national grid operating centre (NGOC) had indicated that the CYD_CML_TWZ circuits were available to be put back into service
11:33	NCC Security Co-ordinator began the process of setting up the system for a resynchronisation of the two parts of the South Island power system using Autosync.
11:42	NCC Security Co-ordinator gave permission to proceed (PTP) to the NGOC Grid Asset Controller conducting the synchronisation operation.
11:43	Initial attempt to re-synchronise using CYD_CML_TWZ_1 failed.
11:44	A second attempt to close the circuit breaker reconnected the two parts of the South Island. Initial data shows the two islands were connected when the island frequencies

	were 0.6 Hz apart and the angle across the closing breaker was approximately 60 degrees at the time of closing. Clyde-Cromwell-Twizel 1 circuit restored.
11:46	Clyde-Cromwell-Twizel 2 circuit restored.
11:48	South Island now one complete and stable system, with Manapouri keeping frequency.
11:52	Instructions to North Island interruptible load providers to restore load began.
12:01	Instructions to South Island distributors to restore AUFLS load began.
12:16	Grid Emergency notice sent and last remaining instruction to restore load given.
12:32	Grid emergency ended with all load able to be restored.

2 INVESTIGATION FINDINGS

This section summarises the key findings of our investigations under the following areas of focus:

- Testing of Protection Schemes (section 2.1)
- Outage Planning (section 2.2)
- System Restoration (section 2.3)
- System Response (section 2.4),

Note: As the main focus of this report is on Transpower's performance as system operator during the event (as a service provider to the industry and Electricity Authority), the section on system restoration goes into more detail about the findings and suggested improvements.

2.1 TESTING OF PROTECTION SCHEMES

Key Finding 1: The event was caused by a failure to identify the recently installed intertripping equipment and therefore its potential effect on the work being undertaken. The failure to identify this equipment meant it was not adequately isolated from being able to send command intertrip signal(s) which opened the circuit breakers creating the two islands. The bus zone CB fail intertrip scheme was complex, with drawings of a low quality. Design of isolation points was unintuitive and impractical to achieve the isolation required to allow maintenance to be carried out.

Key Finding 2: There was a lack of situational awareness by technicians working on the 220 kV protection at Clyde.

Note: This section is a summary of the findings of the BEC Consulting report in Appendix D in relation to Transpower's processes for undertaking testing of protection schemes.

Control systems that monitor equipment (assets) used in the transmission of electricity across the grid are referred to as protection schemes. This control system equipment is located at substations – key nodes on the grid. A protection scheme's primary function is to disconnect the flow of electricity from equipment by operating (tripping) the circuit breakers that connect the equipment to the grid. These schemes will act if they sense a condition that indicates the equipment could be or may be damaged, is not operating correctly, or its continued operation may create a safety hazard.

Protection schemes on transmission lines are often duplicated due to the criticality of correct operation. This allows them to be tested without disconnecting the equipment being monitored. Regular testing is required to ensure correct operation. If testing is carried out with the protected equipment still in service, then the output of the protection scheme must be correctly isolated to prevent inadvertent operation of the equipment being monitored.

Some protection schemes only operate circuit breakers that isolate equipment at the specific substation the scheme is installed at. More complex protection schemes also send signals to other substations to operate circuit breakers remotely. This particular "intertrip" functionality is part of the protection scheme at Clyde substation.

To enable the required testing of a protection scheme, the scheme is isolated so its ability to disconnect equipment is blocked. The circuit breaker failure and bus zone protection scheme at Clyde included an intertrip feature to operate circuit breakers at Twizel substation, which also had to be isolated to enable testing. While the drawings available to the protection technicians were sufficient to enable them to identify the intertrip, the installed design made it difficult to identify how to isolate it for testing.

Transpower requires technicians to plan their work using drawings, but the investigation found there was an "expectation gap" between designers and technicians as to how much investigation is needed to identify how to fully isolate protection schemes for testing.

The investigation found there is a need to ensure the key drawings (relay and instrumentation diagrams) are uncluttered so they are useful, while providing sufficient notes to provide guidance on complex schemes.

The investigation also found the work involved in completing maintenance tasks on protection equipment, such as testing, and how protection technicians undertake these tasks, is not always well understood by designers. The isolation procedures for the bus zone and circuit breaker fail protection scheme at Clyde substation had not been specifically addressed in the design of the scheme.

There is also limited situational awareness for protection technicians when performing testing on site at a substation. At Clyde, the technicians undertook each test without any awareness there had been an adverse outcome, as they were unaware of the resulting circuit breaker operations at Twizel substation.

Where the consequences of any activities can be wider than the immediate substation, seeking affirmation that tests have not led to an adverse outcome elsewhere should be essential to reduce the risk of routine testing triggering major system events.

2.2 OUTAGE PLANNING

Key Finding 3: There was insufficient consideration in the outage planning process of the risks associated with maintenance on 220 kV protection at Clyde during high power transfers from the Lower South Island to Upper South Island.

Note: This section is a summary of the findings of the BEC Consulting report in Appendix D in relation to the planning of the outage and field activities associated with the protection testing which triggered this event.

In the weeks and days leading up to real time, Transpower engages in planning activities based around outages for each day. Two works relevant to the event were planned for 2 March:

- A planned outage removing the Livingston – Naseby (LIV_NSY) circuit from service. This outage left the double circuit transmission lines between Clyde and Twizel (CYD_CML_TWZ_1 and 2) as the sole means of transmitting lower South Island generation to the rest of the country.
- Routine control system maintenance at Clyde on the CB fail and bus zone on the CYD_CML_TWZ circuits. This testing twice triggered a control signal to be sent from Clyde substation to Twizel substation. Correct assessment of testing requirements would have ensured the control signal would be isolated or "blocked" from actuating any electrical equipment.

For the most part, testing of protection schemes does not have a significant effect on system security. The LIV_NSY outage leaving the CYD_CML_TWZ lines as the remaining in-service circuits would not normally be a security concern unless system conditions in real-time led to the circuits being classified as a double-circuit risk[2].

As part of planning and co-ordinating the outages, Transpower engineers assessed the likely impacts and set up the power system and market system to maintain system security, by applying constraints as necessary and briefing the security co-ordinators of any risks.

[2] Meaning there is a risk of having both circuits trip simultaneously. Usually this is a result of adverse weather conditions such as lightning storms close by.

While some planned testing of complex protection schemes are referred for advice from experts on possible system risk, in this event the concurrence of testing a complex protection scheme and potential for high system consequences had not been recognised and so additional advice was not obtained.

Requiring an expert in protection schemes to review all protection tests is not practical due to the sheer number of tests. Most tests are on standard protection schemes with a low system impact. The investigation found that it would be preferable to use an updated approach that identifies where there is a combination of high risk protection scheme and high system criticality to reduce the risk of major system events being triggered by protection testing.

2.3 System Restoration

Given the system operator is a key service provider to the Electricity Authority and plays a critical role in co-ordinating industry response in major events, this section goes into a greater level of detail than the other sections.

2.3.1 Summary of overall system co-ordination during the event

NCC's priority following an event is to stabilise the power system, i.e. to restore the ability of the system to tolerate fluctuations in frequency and voltage. The second priority is to restore system security, which is the ability of the power system to handle a subsequent event. Thus, the immediate focus after the event was for the NGOC and NCC teams to ensure system stability across the two new 'electrical islands'. This was complicated by a very dynamic situation in the short period following the second circuit tripping.

- An unplanned gradual reduction of 150 MW of generation in the upper South Island with no known reason at that time[3].
- Genesis Energy's Tekapo A station reverted to a different mode of operation, making it unable to support the wider power system.
- Difficulty in determining how to re-dispatch the HVDC link with the now separate upper South Island and lower South Island systems[4].
- Other grid activity occurring (e.g. a transmission circuit tripping in the upper North Island).

In the lower South Island, a surplus of generation was managed by over-frequency reserve tripping some generating units.

[3] This was due to an unexpected reduction in output from Aviemore (AVI) generation station. The cause has been identified and rectified by Meridian Energy. The runback of AVI just after the primary event was not initially obvious to the Energy Co-ordinators, due to AVI output indications being part of the Waitaki river block dispatch. The other generators within the WTR block had ramped to save the upper South Island frequency; a result that increased output helped mask the AVI runback. It was not until later in the event a system operator support staff member identified the extent of the AVI problem.

[4] During events the HVDC frequency stabilisers allow the HVDC transfer to vary from its dispatch set-point by up to 250MW; this variation is greater than the grid owner's offered ramp rate of 25MW per minute. Post event this difference can make it difficult to produce a real-time dispatch (RTD) solve that meets the Code-specified dispatch objective. Unlike a generator, the market system Scheduling Pricing and Dispatch (SPD) solver does not have an offered ramp rate for the HVDC; instead the market system automatically creates minimum and maximum HVDC constraints with every solve. These minimum and maximum constraints will limit the HVDC to 125MW from the last dispatch, even if the HVDC has already responded to a value beyond the 125MW (i.e. is physically operating at transfer levels different to that modelled in SPD). This situation can give the appearance of the HVDC being dispatched in the opposite direction (up or down) to what is needed.

In the upper South Island there was a deficit of generation, managed by AUFLS and the HVDC link ramping back, but frequency was continuing to decay. This threatened both the stability of the island and the ability of the island to handle a subsequent event.

The NCC system co-ordinators followed established procedures to review the steps to manage system voltage and frequency, and consider options for reconnection of the electrical islands.

The feasible options, following stabilisation of the two islands, were to:

- reconnect the two South Island electrical islands (using verbal rather than electronic dispatch to align frequency and voltage between the two islands), then re-establish economic dispatch across the South Island and then commence restoration of disconnected load;
- maintain the two electrical islands in the South Island and align dispatch of the electricity market with the new grid configuration (i.e. establish economic dispatch separately in each island), then reconnect the two electrical islands, re-establish economic dispatch across the South Island and commence restoration of disconnected load.

Based on the information available, it was deemed reasonable to reconnect the two South Island electrical islands (the first option), to strengthen and stabilise the South Island system using the recently installed Autosync facility at Clyde.[5] A standard operating procedure for using Autosync was available to both NCC and NGOC personnel. This procedure was not referred to (and therefore not followed).

Two attempts to close the circuit breaker to reconnect the islands were carried out manually, under the belief the Autosync tool was enabled and would act only after the frequencies in the islands were inside the range within which the Autosync tool could operate. Since the Autosync tool was not enabled and the co-ordinators had not brought the two island frequencies into sufficient alignment, the second attempt succeeded in connecting the islands, but there was a substantial misalignment between the upper South Island and lower South Island systems on reconnection. [6]

2.3.2 Areas of focus for the investigation

In carrying out the investigation into the system operator's performance, three areas of particular importance were identified:

1. The suitability of the operational communications, event management and situational awareness of the system co-ordinators, NGOCs and generation controllers during the event (covered in section 2.3.3 and 2.3.4).
2. The difficulties faced by the system co-ordinators in using the real-time dispatch software to control the power system (covered in section 2.3.5); and
3. The decision to re-synchronise the South Island electrical islands using the Autosync tool, and execution of that operation (covered in section 2.3.6).

2.3.3 Operational Communications, Event Management and Situational Awareness

Key Finding 4: Our operational communications were insufficiently clear, formal and effective.

Key Finding 5: There was a lack of effective event management between the NCC and NGOC operators which impacted their situational awareness and their ability to enact the most effective restoration.

[5] This was the first time that Autosync had been used on the system to reconnect separate power system 'islands' since installation of this facility in 2014.
[6] The phase angle difference between the two 'islands' was 120 degrees on the first attempt and 60 degrees on the second attempt.

As already mentioned, the event was complex and constituted several elements, each of which was individually an event of significance – the initial Clyde–Cromwell-Twizel-2 220kV circuit tripping; the upper South Islands AUFLS tripping; the North Island under frequency event and, shortly after the main event sequence, a run back of Aviemore generation (resulting in a further fall in frequency). In all, the NGOC and NCC operators faced a very complex and fast changing situation. This provides context for understanding the actions taken by the real-time operators.

The investigation into the system operator's performance made extensive use of the voice tapes recorded with every phone call to and from NCC. It is clear from these tapes the quality and clarity of the operational communications during this high-pressure, complex event did not meet the standards expected of operational communications[7] and this impacted on the parties' situational awareness and their ability to effectively manage the event.

In the first minutes following the event, NCC engaged in several phone calls to Meridian and Contact generation controllers and to the NGOC grid asset controllers in Christchurch. The communications during these calls were often unclear, with inadequate formality meaning critical situation updates and instructions from NCC co-ordinators were, at times, misunderstood. Misunderstandings from the verbal exchanges were compounded by apparent conflicts with the electronic dispatches being sent during the event.

2.3.3.1 Communications with Generators

NCC's communications with generators during the event did not meet Code obligations for clear, concise and effective verbal communications – this included frequent instances of insufficient formality and failure to confirm instructions.

Of all the communications during the event, those between the NCC energy co-ordinators and Meridian generation controllers were arguably the most critical in terms of managing the event because of Meridian's greater ability to assist with the rebalancing of the two electrical islands.

The NCC energy co-ordinator failed to relay several key details required for the Meridian generation controller to understand the instructions, or contribute to assisting in stabilisation:

- The South Island had been split between Clyde and Twizel (the energy or security co-ordinators did communicate that another island had been created, but did not specify where the island was).
- At 11:23, multiple frequency keeping had been disabled and single frequency keeping had been enabled, and that the split in the island required two separate frequency keepers in the South Island.
- The electronic dispatch tool, set up to dispatch frequency keeping as if the South Island were a contiguous whole, was unable to issue electronic frequency keeping dispatches.
- No details were given about the frequency keeping band size (MW).
- There should have been an instruction to disregard electronic dispatches until further notice.

The lack of clarity from the NCC energy co-ordinator meant several important instructions including dispatches for energy and frequency keeping were misunderstood. Coupled with the inability of the electronic dispatch engine to satisfactorily calculate dispatch, while continuing to send instructions, Meridian controllers were unable to respond adequately to the system event.

[7] Electricity Industry Participation Code 2010, Schedule 8.3, Technical Code C, 3(1)

2.3.3.2 Communications with NGOCs

Communications between NCC and the NGOCs also did not follow the standard protocols in some cases. While, the instructions to prepare to align the two systems for the planned resynchronisation were correct, clear and acknowledged, the communications during the attempted operation of the Autosync tool indicated that both parties were unsure and unclear on the process.

2.3.3.3 Wider industry communications

Industry-wide situational communications were not sent until well after restoration commenced. Sending notices is generally not a priority activity during system events unless the recipients are able to directly aid in restoration. However, the lack of information resulted in several participants contacting NCC asking about expected times for restoration. This had a negative impact on operations as the co-ordinators had to manage incoming calls while also attempting to manage a difficult complex system event, which resulted in frustration, evidenced in the phone calls with participants. Sending notices earlier, even with limited knowledge, and with instructions to limit calls to NCC pending further updates, would likely have addressed these issues.

2.3.4 What is being done to address the issues with operational communications?

2.3.4.1 Operational communications training

During situations of high stress, remaining calm and focused can be challenging. This is often evidenced in the way we communicate under pressure, and was seen during this event in many interactions in which good operational communications practices were not followed. Following the event, operational communications have received greater focus in NCC and NGOC during normal operation, and within training on our simulator. An ongoing challenge is how to recreate the pressure of a major system event in our training and simulations - often it is not until an actual event is experienced that lessons can be truly tested. Improving communications in these contexts requires ongoing monitoring and feedback for staff to recognise deficiencies, build up skill sets and change behaviour accordingly. This has been implemented as part of more general human factors training as discussed below.

2.3.4.2 General training development

Prior to the event, NCC had already taken the opportunity to improve training related to human factors (and subsequently the NGOC controllers have also undertaken similar training). Human factor training has developed out of the commercial airline industry, recognising the significant impact the performance of airline pilots can have on safety outcomes. It focuses on non-technical training relating to behaviour and personnel performance. This approach has been adopted extensively by other sectors involving high-risk operations, including the nuclear power and oil and gas industries.

Prior to developing and implementing an internal training course, human factor training was covered by annual workshops from international experts. While valuable, the external providers noted that the training is best developed within the environment to which it applies. Each industry has its own set of cultural and risk factors which must be considered for effective human factor training. Hence, an internal training course was developed, which presents relevant material in a way that allows flexibility and repeatability. It covers the following areas:

- effective control room performance
- human factors in the control room
- communications
- teamwork

- situational awareness
- decision making

All of these aspects are relevant in management of significant system events such as the 2 March event, but the skills themselves are developed day-to-day during normal operation, so that when emergencies occur the skills required to manage the event are innate. Utilising fit-for-purpose training for continuous development of these skills will improve the ability of the co-ordinators to manage system events.

We are reviewing how this training can be further enhanced and reinforced.

2.3.4.3 Sharing skills with other controllers and operators

Much of the knowledge Transpower has gained as a result of this event would be equally well applied in other control centres. It is also useful to take the opportunity to assess the interactions of other participants during this event, and engage with the rest of the industry as to how all parties can work together effectively during a major system event. In particular:

- how and when grid emergency notices can practicably be communicated during an event to improve the speed of industry awareness;
- when it is appropriate to contact NCC for direction, and when to wait for the co-ordinators to contact them;
- all parties' operational communications in operational environments should endeavour to meet the same standards in use of command language, to ensure information is delivered accurately and instructions are understood[8].

Since 2016, Transpower has engaged with industry operational personnel several times a year via system restoration workshops. These workshops are intended for operational staff across the power industry to come together to understand and validate Transpower's plans for managing system restoration. Many of the skills practiced in these workshops test the restoration processes that are applied in both black start and other event management. These forums provide a good opportunity to communicate the lessons learned to the rest of the industry at an operational level. However, since by necessity these workshops are limited to the operational personnel who are available to attend on the day, these sessions rely on the attendees sharing the lessons with their counterparts.

More functionally, we are investigating what improvements could be made to the ways customer notices are prepared and sent, particularly during system events. In this event it would have been beneficial for both the industry and the co-ordinators to broadcast updates during the event to limit the number of phone calls to NCC, allowing the necessary information to be communicated without compromising the efforts of the co-ordinators to manage the event.

2.3.5 Modelling the dispatch solution

Key Finding 6: Our market system software (SPD) can be difficult to remodel in real-time following major system events. This means there are delays in achieving a post-event return to economic dispatch.

Transpower as part of its normal day-to-day management of the power system must model its physical topology. Transpower relies on information from asset owners about their asset capability and availability. This modelling process includes steps to update the model for planned outages and unplanned outages. Changing the status of an asset, be it capability or availability, can influence many

[8] Electricity Industry Participation Code 2010, Schedule 8.3, Technical Code C, 3(1)

other assets within the system and accuracy of the model is important. A key aspect of outage planning is studying the impacts on the power system of model changes.

The model is a key input in Transpower's Scheduling Pricing and Dispatch (SPD) software, from which dispatch and pricing schedules are calculated and dispatched to generators. Before changing the model, Transpower must understand what has happened to an asset and why. If an inaccurate change is implemented, it could further exacerbate a complex situation. During a major unplanned event, any change must be studied to ensure it is accurate. This can take time to both implement into the software and test to ensure what is dispatched as a result influences the power system as expected to assist in managing the event.

2.3.5.1 Co-ordinator actions and HVDC Modelling

The initial response of the power system following the second circuit trip was a reduction in HVDC north flow to arrest the fall of frequency in the upper South Island. This is an automatic and expected response of the Frequency Keeping Control (FKC) system. The HVDC link is limited to a maximum instantaneous change in transfer of ±250 MW in a system event, which was achieved in this event. The ramping limit of the HVDC is set at ±125 MW during normal operation to preserve system stability.

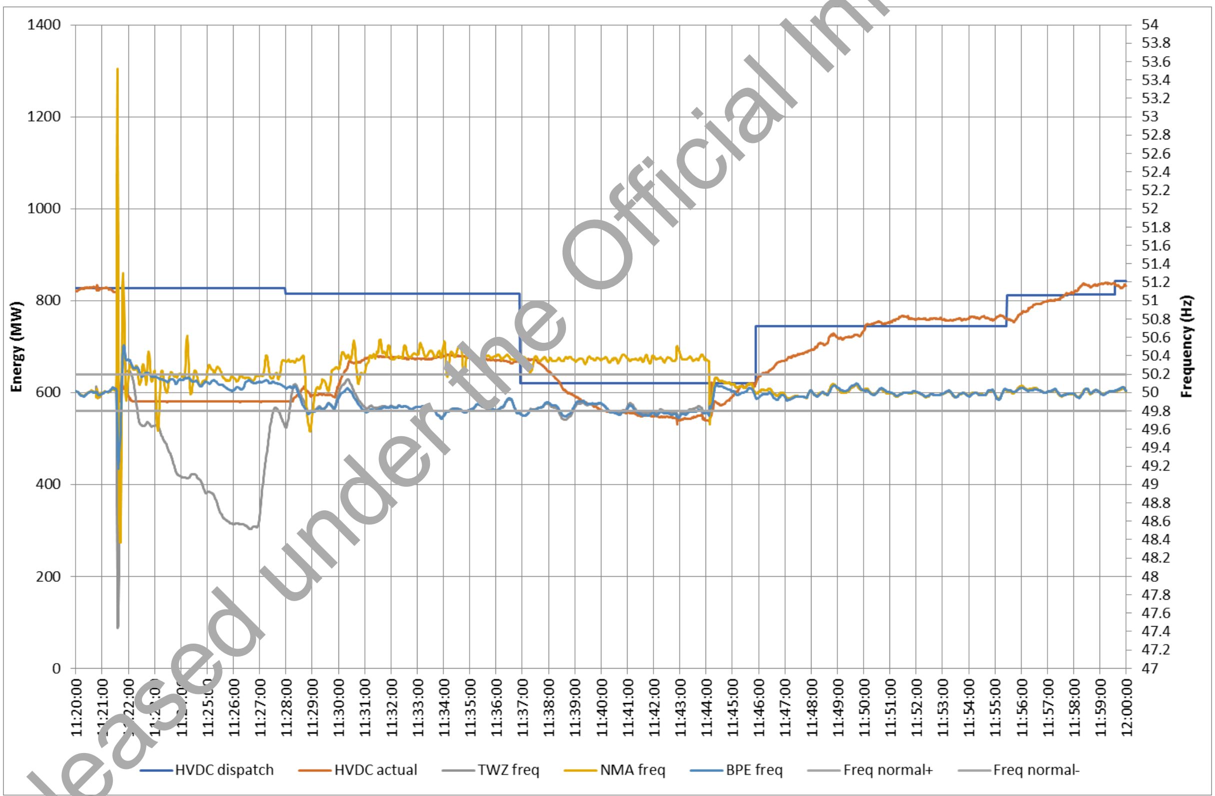


Figure 4 – HVDC link response vs. dispatch, and system frequencies during the event. Note HVDC transfer (red line) drops immediately following event and remains at minimum modulation until TWZ system frequency returns to the normal band. HVDC transfer and dispatch only converge following South Island re-synchronisation at 11:44.

While the duty energy co-ordinators managed the initial stabilisation, the day-work energy co-ordinators provided their support to attempt to model the new system conditions in the market system to generate a new dispatch solution. The new dispatch solution would allow generation to match the load in both the lower South Island, and the upper South Island and North Island (joined by the HVDC link). The approach taken by the co-ordinators was to attempt to constrain the solution to match the real condition of the HVDC link. Once this condition was met, the generators would be dispatched to meet that transfer.

The market system uses a set of constraints to model HVDC link operation, to prevent HVDC power orders (dispatches) which exceed the capability of the link. The image below shows the HVDC constraints applied to the real-time dispatch (RTD) schedules with present-day limits. One of these constraints is the bipole north transfer lower limit (DCNMin) constraint, the limit of which is calculated as the previous dispatched quantity minus 125 MW (the ramping limit for normal operation). This limit is also used in the HVDC control system.

Constraint	Type	Ineq	Protected Branch	Limit
DCNResShareMax	BrCnst	<=	N/A	1001.0
DCNmax	BrCnst	<=	N/A	849.7
DCNmin	BrCnst	>=	N/A	599.7
DCP2Nmax	BrCnst	<=	N/A	420.0
DCP2Smax	BrCnst	<=	N/A	420.0
DCP3Nmax	BrCnst	<=	N/A	780.0
DCP3Smax	BrCnst	<=	N/A	[illegible]
DCSResShareMax	BrCnst	<=	N/A	[illegible]
DCSmax	BrCnst	<=	N/A	0.0
DCSmin	BrCnst	>=	N/A	0.0

Figure 5 – Extract from the market operator interface showing constraints applied in the RTD schedule to model HVDC link.

The 11:20 RTD schedule calculated an HVDC dispatch of 826 MW north, with subsequent dispatch schedules automatically taking this value and using it to calculate the new DCNmin constraint of 701 MW (826 – 125 = 701). This meant the minimum transfer level to which the HVDC link could be dispatched using RTD was 701 MW.

The actual HVDC transfer following the event had dropped to 580 MW, which was not being reflected in the dispatch calculation. Seeing the dispatch of 701 MW, the energy co-ordinators had the perception that the HVDC was being dispatched *up* from its present transfer level (580 MW) to 701 MW, at a time when the upper South Island frequency was low. With low frequency, it would be expected that the HVDC transfer was minimised to raise upper South Island frequency.

It took several attempts to manually bypass this minimum HVDC constraint to produce a dispatch solution with a HVDC value that seemed logical at the time. From the Manual Operator Log at 11:32:

> *HVDC 170MW under dispatched following the SI event. HVDC Ramp Rate changed to 0MW to see if this will align the MOI dispatch with HVDC actual transfer. Didn't have the desired effect.*

The modelling issue was eventually resolved at 11:36 by overriding the transfer limit to 650 MW. This effectively fixed the modelled quantity of the HVDC transfer at 650 MW and allowed a more realistic generation dispatch solution. At this time, the NCC security co-ordinator had begun to prepare for re-synchronisation, understanding that for re-synchronisation to occur the upper and lower South Island system conditions would need to converge.

2.3.5.2 Electronic vs verbal dispatch

Generation dispatch is generally managed by Transpower's SPD software, with NCC energy co-ordinator oversight and minor schedule adjustment as required. Dispatch instructions are normally sent and received by electronic means; generators are obliged to meet the electronically delivered dispatch. During events, the nature of the event might mean that dispatch (e.g. managing frequency) might have to be materially different (in some geographical areas or to some generators) than is produced by SPD. In such cases, the NCC energy co-ordinator may verbally dispatch a generator to a set point different from the position 'required' by SPD-configured dispatch. In this case, the verbal dispatch instructions override the electronic.

The market system automatically runs dispatch schedules every five minutes, starting one minute before the interval. The system is typically set to auto-dispatch unless the post schedule check (PSC) or co-ordinator intervention switches dispatch to manual. Manual dispatch schedules can also be executed.

Prior to the event, the latest dispatch was valid from 11:20. During the event up to re-synchronisation and return to service of the first CYD_CML_TWZ circuit at 11:46, 13 dispatch schedules were produced. Electronic dispatches were sent from five of those schedules, at 11:28, 11:33, 11:37, 11:39 and 11:46. From the dispatch times, it is clear auto-dispatch was disabled. However, from soon after the trippings, the co-ordinators had intended to verbally dispatch both Meridian and Contact to remain at their current output, which for Manapouri at least was significantly lower than the electronically dispatched output. The lack of clarity of these communications meant that confusion subsequently resulted and restricted Meridian's ability to assist with restoration.

The NCC energy co-ordinators were motivated to dispatch from these schedules based on the information they had available at the time of the event. A difficulty with using the electronic toolset is when a dispatch schedule is produced, the co-ordinators can either dispatch all generating plants ("send all") or select individual plants for dispatch. They cannot, without difficulty, select a set of generating stations or exclude the lower South Island generating stations from the electronic dispatch instructions set. In this event, it would have been useful to be able to exclude lower South Island generating stations from the electronic dispatch and instead have Manapouri keep frequency in that island, with relatively stable load. Meridian and Contact generations controllers, having received verbal instructions to hold Manapouri and Clutha output steady, were then confused with electronic dispatches instructing them to increase output to pre-event levels.

These difficulties partly contribute to the current policy of using manual dispatch over electronic dispatch in the re-stabilisation phase of managing emergencies. From the Policy Statement[9], clause 84 (emphasis added in bold):

> *Where restoration is required, the system operator must use the following methodology to re-establish normal operation of the power system by: ...*
>
> *84.3 Stabilising any remaining sections of the grid and connected assets and the voltage and frequency of the grid,* ***through the combination of manual dispatch instruction and allowing automatic action of ancillary services and governor and voltage regulation operation by generating plant,*** *and including any necessary disconnection of demand.*

2.3.5.3 Modelling of CYD_CML_TWZ circuits

The market model SPD uses to produce the dispatch solution is normally electronically updated to reflect the grid owner's offer. Following a system event, there is always a time delay while the grid owner determines if it is safe to return a tripped or faulted asset to service or if a change to offer is required. In the time between the tripping or fault being evident and the grid owner making the asset 'available for service' or making a 'change to offer' the actual grid and the offered grid will not match, SPD will still solve and produce dispatch schedules as if the tripped or faulted assets remained in service.

The system operator can manually apply dispatcher discretion, constraints or overrides to the market model (in SPD) to align the offered grid and the actual grid[10]. If time doesn't permit manual updating of

[9] Incorporated by reference into the Code

[10] The System Operator is required under the Code to use (among other things) "information from the grid owner". The dispatch schedule must also use "adjustments required to meet the dispatch objective". The adjustments may include (among other things) "additional transmission constraints". Clause 13 of Schedule 13.3 then describes the form of these constraints as minimum or maximum flow limits on assets modelled as branches or groups of branches in SPD.

the SPD model it may not be possible to for SPD to produce a completely usable solution. In such events, a verbal dispatch will be used to stabilise the power system until the equipment is restored or the SPD market model is updated.

In this event, the grid owner did not offer-out the CYD_CML_TWZ circuits. This reflects Transpower's current practice where assets remain offered despite tripping, on the basis that tripped assets can generally be reinstated reasonably quickly if no physical damage or disablement has occurred. Therefore, assets initially remain offered anticipating a quick return to service, until it is confirmed that they need to be removed from the offer. However, NGOC's procedures do require that if a cause cannot immediately be established (as was the case in this event), then the circuits should be offered out. This procedure wasn't followed in this event. To accurately model system topology for SPD to solve correctly, the co-ordinators would have needed to model the circuits as out of service.

To generate a suitable dispatch solution, the co-ordinators' first action was not overriding the grid owner's offer of the CYD_CML_TWZ circuits, instead they focused on adjusting the HVDC modelling. Overriding the grid owner's offer in practice relies on the co-ordinators having knowledge over and above the grid asset controller's situational awareness, and uses a process which is complex and rarely applied. This process requires knowing with some certainty when the override will no longer be required (to set the end time). There is considerable risk in this approach in creating unintended consequences, generally as a result of the overrides not ending at the appropriate time. This approach is therefore not practiced as part of normal operations, and is seen as difficult to execute especially in a stressful situation where the risk of error is high.

2.3.5.4 Potential improvements to the market system interface

The event has highlighted difficulties the co-ordinators have when trying to manipulate the market system following a significant event. In this event, two sets of changes were required to allow the dispatch engine to solve with some semblance of reality: the HVDC modelling parameters needed to be overridden, and the CYD_CML_TWZ circuits needed to be modelled out of service. Neither of these processes are part of normal operations and can be difficult and unreliable to execute in practice.

Training post-event has included emphasis on market system modelling capabilities. In addition to technical training which aims to improve the co-ordinators' skills in modelling constraints and overrides, we propose investigating the feasibility of making changes to the market system software which remove constraints related to normal operation in abnormal events. These changes will be planned and developed alongside other market system enhancements. In addition, we will assess whether there are other potential options for how the market model and SPD could be enhanced to enable them to better assist co-ordinators in restoring the system after a major event.

2.3.6 Resynchronisation using Autosync

Key Finding 7: The procedures for using the Autosync tool, returning assets to service and voice communications were not followed. Operation of the Autosync tool was not well understood by either NCC or NGOC personnel.

2.3.6.1 Context

The incorrect attempt to use the Autosync tool was one of the key concerns arising out of the investigation because of its potential serious impact on generating units. This section outlines the purpose of the tool; the decision to use it on the day; what went wrong and the impact.

2.3.6.2 Background to development of Autosync

The Autosync function was installed at selected Transpower substations across the grid between 2011 and 2015. It provides the ability to reconnect separate electrical 'islands' that may form after a major power system event.

Manual reconnection of electrical 'islands' requires skilled operators to travel to substations to operate equipment after an event. The Autosync functionality and associated tool was developed to remove reliance on manual synchronisation at power stations, reducing restoration time in a situation requiring urgent action. Using the Autosync tool to reconnect separate 'islands' enables more rapid restoration as all action to resynchronise occurs in control rooms, led by system co-ordinators and NGOC grid asset controllers.

2.3.6.3 How is Autosync intended to be used?

Each Autosync scheme monitors voltage, frequency and the phase angle difference between separate electrical 'islands' when they occur. When the scheme is enabled, the Autosync equipment will wait until there is a close match between these parameters and when these two systems are closely aligned it will close the circuit breaker to reconnect the islands. If there is not acceptable alignment within a 5-minute period, the scheme will 'time out' and need to be re-enabled before further reconnection attempts can occur.

To enable the Autosync function, manual steps need to be completed by NGOC grid asset controllers and NCC system co-ordinators through a dedicated Autosync tool interface, part of the computer software used to monitor and control the grid and power system (SCADA). Written procedures set out all the steps to be taken, and are drafted to ensure grid asset controllers and system co-ordinators cross check each other's actions. Training on the use of Autosync was provided to NCC system co-ordinators and NGOC grid asset controllers at its initial commissioning. This was one-on-one training based around the written procedure document published at the time the training was delivered. NCC system co-ordinators received some additional training using Autosync during a 2016 event simulation; though without the benefit of an Autosync-capable simulator.

2.3.6.4 Instructions to grid asset controller

The NCC security co-ordinator contacted the NGOC grid asset controller at 11:33 to outline the "plan of attack" for re-synchronisation of the two South Island electrical islands. Approximately 11 minutes had passed since the event, at which time the NCC security co-ordinator believed there was enough understanding about the situation to allow the co-ordinators and grid asset controllers to proceed with restoration. The call lasted for 16 minutes, during which time the plan was described, preparatory switching was instructed and completed, and re-synchronisation completed resulting in reconnection of the two islands. The call is interrupted frequently with multiple alarms, unrelated asset trippings, and queries from the NCC energy co-ordinators.

From the outset the NCC security co-ordinator describes the intention to re-synchronise at Clyde using circuit breaker CB_542, where the Autosync tool is installed. If enabled, activation of the Autosync tool would have allowed the tool to monitor frequency at both the Clyde and Twizel substations, and automatically close CB_542 when the frequencies, voltages and phase angles of the two islands were in alignment.

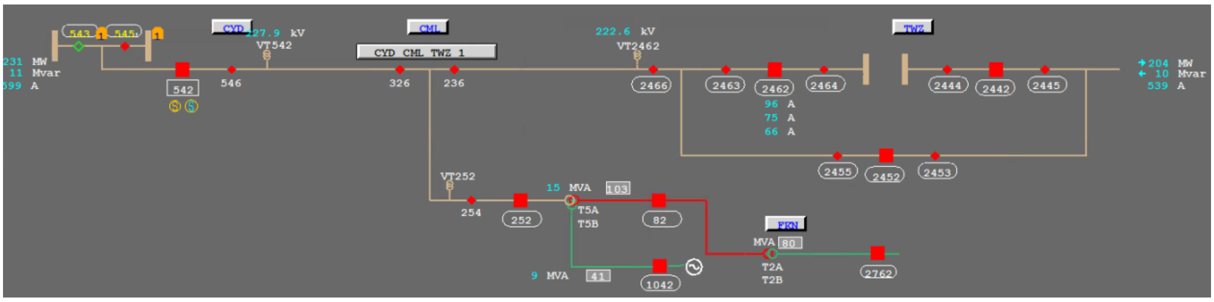


Figure 6 – SCADA single line display of CYD_CML_TWZ_1 circuit. Note symbols below CB_542 on left hand side of the display indicating this breaker has Autosync available.

The procedure to operate Autosync was not accessed (or followed) during this period. When the security co-ordinator instructed the action to close the circuit breaker and the grid asset controller attempted to operate Autosync, normal manual switching occurred instead. Neither the security co-ordinator or the grid asset controller were aware of the misalignment in island frequency and phase angle; they simply saw that the circuit breaker had closed, and current was flowing on the circuit. The security co-ordinator and grid asset controller then proceeded with switching to restore the second circuit.

2.3.6.5 Why was Autosync not enabled?

The Autosync design assumed that following creation of electrical islands, there would be time to develop a strategy for reconnection and that procedures would be accessed and read – time was not taken in this case, with a rapid decision made to use the Autosync tool.

This design assumption resulted in a tool where:

- the Autosync equipment needs to be correctly, manually enabled to manage resynchronisation
- if not enabled, it was still possible to attempt reconnection despite electrical islands being severely misaligned
- no automatic systems existed to block and prevent mal-operation by system co-ordinators or grid asset controllers.

This system event resulted in a high-pressure control room environment with a perceived urgent need to stabilise and strengthen the power system to prevent any further disruption. Assumptions made during the Autosync installation project as to how the Autosync tool would be used were shown to be flawed in this event.

The procedures for the use of the Autosync tool do not provide easily accessible guidance in managing a rarely used tool. The displays in the computer software used to monitor and control the grid and power system (SCADA) do not have an interface design that prevents or even reduces the likelihood of false operation.

2.3.6.6 Impact of not enabling Autosync during restoration

When both reconnection attempts were made, the upper South Island and lower South Island electrical 'islands' were misaligned. This was identified by a review of power system performance during reconnection shortly after the event.

Reconnecting two electrical islands when they are significantly misaligned (i.e. out of synchronisation) can result in large instantaneous forces being applied to all connected generators in each electrical island when they are reconnected. These forces attempt to immediately accelerate or decelerate the large heavy rotating mass of each connected generating unit. As a result, potential damage can be sustained by generating units.

South Island generators were contacted immediately after the event, requesting they check their generating units. A formal notice was also issued. No reports of damage have been received to date although generators have advised that the added stresses experienced on generating units may change the timing and nature of future major maintenance.

Subsequent calculations were carried out to estimate the forces applied to generating units during both reconnection attempts, supervised by an independent expert investigator. The independent report finds that for this event, the instantaneous forces (or transient electrical torques) were comparable to the forces that would be applied to a generating unit if a major electrical fault occurred within the substation connecting a generating unit to the power system. All generating units connected to the New Zealand power system are required to survive such a fault. Refer for details to the PSC Consulting report in Appendix C.

2.3.6.7 Autosync training and improvements

Following this event, a full Autosync tool model has been added to Transpower's power system training simulator. Since that time, all NCC system co-ordinators and NGOC grid asset controllers have completed a training exercise using Autosync on the simulator.

Future simulation exercises will combine NCC and NGOC staff in joint Autosync operations; these will be scheduled periodically as part of the regular risk-based training syllabus.

Some simple changes to computer displays made since this event will support correct use when decisions are made under pressure; however, they will not prevent mal-operation.

An approval requirement (in the operational procedure) has been implemented, mandating senior manager authorisation and validation before use of the Autosync tool.

In November 2017 the Autosync tool was used during a generation station black start test carried out in the South Island (as realistic a simulation of operational use as is possible). This test provided further training and process validation.

Separately, we are investigating using Sync Check functionality for manual switching operations on circuit breakers where it is installed. Sync Check is used for some circuits which can auto-reclose where the circuits connect to a generating station, and ensures that if the system frequency and station frequency are misaligned then the automatic switching connecting the generator back to the grid will be blocked. This allows an extra validation step for manual switching operations to reduce the likelihood of manual switching on unsynchronised systems.

2.3.6.8 Improvements for Autosync software

One of the critical failings of attempting to operate Autosync during this event was that the interface was not intuitive and did not safeguard against mal-operation. In part, these risks were mitigated by development of an operational procedure, but in this event the procedure was followed, and the security co-ordinator and grid asset controllers relied instead on their own (limited) knowledge to use the tool. While Autosync is a switching interface, the same lessons can be applied to the operational and market system interfaces used by the system co-ordinators.

We are investigating how the user interface for the Autosync tool can be improved. In designing operational interfaces, a lesson from this event is that they should be built to tolerate use in adverse conditions, with appropriate interlocks and validation rules.

2.3.7 Risk Management

Some of the matters discussed in this section have raised questions about the important controls Transpower relies upon to manage its risk around high-impact, low-probability (HILP) events, in particular our software tools, training programmes and compliance with policies and procedures. While we believe our risk management programme is robust, we are looking at the failure of the identified controls to assess whether there are any issues relating to the management of those controls that need to be addressed. We will also engage an external party to provide assurance about the management of these controls.

2.4 SYSTEM RESPONSE

Key Finding 8: The configuration of two distribution networks in the upper South Island reduced the effective amount of AUFLS provided.

System response was extensively reviewed by PSC Consulting, attached to the report as Appendix C. Two issues of note were AUFLS operation in the upper South Island and over-provision of interruptible load in the North Island, as described below.

2.4.1 AUFLS operation in the upper South Island

The first stage of the two-stage automatic under-frequency load shedding (AUFLS) scheme was triggered in the upper South Island only. AUFLS operation was not required in the lower South Island. The load connected to AUFLS is relatively evenly spread across all substations in the South Island.

As a result, the actual proportion of upper South Island load shed by the first stage of AUFLS in the upper South Island was close to the 16% required for the activation of the first stage across the whole of the South Island.

For two distribution companies in the upper South Island the first stage of AUFLS was activated but the full load reduction did not occur. This was discovered to be due to the way the distribution networks and connections to the substation were configured. This has been addressed with the two distribution companies involved. This issue has also been drawn to the attention of all other distribution companies in the South Island to ensure this is not a widespread problem.

2.4.2 North Island Interruptible Load response

Significantly more interruptible load (almost 400MW) responded to the North Island under-frequency event than was dispatched (only 204 MW). This is because interruptible load is generally armed to trip regardless of dispatch instruction. Although there was no obvious impact this behaviour continues to occur as Interruptible Load providers leave their load connected to respond, even when they have not been dispatched to provide reserves.

3 Findings And Actions From The Event

3.1 Summary of Key Findings

Key Finding 1: The event was caused by a failure to identify the recently installed intertripping equipment and therefore its potential effect on the work being undertaken. The failure to identify this equipment meant it was not adequately isolated from being able to send command intertrip signal(s) which opened the circuit breakers creating the two islands. The bus zone CB fail intertrip scheme was complex with drawings of a low quality. Design of isolation points was unintuitive and impractical to achieve the isolation required to allow maintenance to be carried out.

Key Finding 2: There was a lack of situational awareness by technicians working on the 220 kV protection at Clyde.

Key Finding 3: There was insufficient consideration in the outage planning process of risks associated with maintenance on 220 kV protection at Clyde during high power transfers from the Lower South Island to Upper South Island.

Key Finding 4: Our operational communications were insufficiently clear, formal or effective.

Key Finding 5: There was a lack of effective event management across the NCC and NGOC operators which impacted their situational awareness and their ability to enact restoration.

Key Finding 6: Our market system software (SPD) can be difficult to remodel in real-time, following major system events. This means there are delays in achieving a post-event return to economic dispatch.

Key Finding 7: The procedures for using the Autosync tool, returning assets to service and voice communications were not followed. Operation of the Autosync tool was not well understood by either NCC or NGOC personnel.

Key Finding 8: The configuration of two distribution networks in the upper South Island reduced the effective amount of AUFLS provided.

3.2 Actions

Transpower has already completed a number of actions in response to the findings in this report and has also identified a number of other actions which are either underway or have been recommended for further development. A summary of these actions as they relate to the key findings is set out below. Transpower will also publish a separate, more detailed action plan and regularly report on progress until the actions are completed.

Actions	Key Finding no.	Status
1. Agree an approach, to be used in future, by protection designers and technicians, to enable access to site-specific information on protection schemes.	1, 2	On track June 2018
2. Develop a process that supports protection designers in gaining clarity on isolation, testing and maintenance requirements for future protection schemes early in the design process - allowing for	1, 2	On track June 2018

Actions	Key Finding no.	Status
appropriate consultation with protection technicians who will be undertaking the work.		
3. Consider providing real-time SCADA data to technicians	1, 2	On track June 2018
4. Improve current outage planning processes to include a risk based approach that assesses requests for outages of protection equipment to identify maintenance activities that have a high system impact (including the impact of other concurrent planned outages).	3	On track June 2018
5. Review the existing Autosync tool and procedures to support NGOC grid asset controllers and NCC system co-ordinators working under pressure.	7	On track June 2018
6. Re-emphasise and embed through regular training of NGOC and NCC staff the importance of compliance with policies and use of procedures during restoration after rare events.	5, 7	Complete
7. Review procedures across Transpower regarding handover of tools and systems to ensure the tools and systems are able to be effectively operationalised	7	Not started Dec 2018
8. Investigate improvements in the design and use of the market model and market system to assist in the management of large scale system restoration events	6	Not started Dec 2018
9. Work with industry and real-time teams within Transpower to address issues with operational communications	4, 5	On Track Dec 2018
10. Work with generators to assess what real-time information could assist them with visibility of the system during events and investigate the practicability of providing this.	5	On track Dec 2018

Appendix A: Glossary

AUFLS	Automatic Under-Frequency Load Shedding; a system by which load is automatically switched off if frequency falls to a given frequency.
Auto-reclose	The circuit breakers at either end of the circuit can open to clear a fault, then quickly re-close to allow the asset to remain in use
Frequency Keeping Control (FKC)	A part of the HVDC link control system which ties the frequency of the North and South Islands, allowing reserve response in one island to maintain frequency in the other.
Grid Emergency	A state of operation where an event requires urgent action from participants to alleviate the situation.
Instantaneous Reserve (IR)	Back-up generation or interruptible load procured and dispatched to mitigate the risk of a credible under-frequency event.
Interruptible Load (IL)	A form of instantaneous reserve by which load is switched off automatically if frequency falls below 49.2 Hz.
Island (electrical)	A separate power system consisting of generation and load, disconnected from the rest of the grid.
MVAr	Mega-Volt Ampere reactive, a unit of reactive power.
National Co-ordination Centre (NCC)	The system operator's central point of control for the power system.
National Grid Operating Centre (NGOC)	National Grid Operating Centre, the central point from which Transpower's grid assets are operated.
Phase angle difference	A measure of the synchronism of the AC voltages between two electrical systems.
Protection (electrical)	A type of automatic control system which switches out equipment on the grid in response to faults.
SCADA	Supervisory Control and Data Acquisition, also used as the name for the control system for the national grid assets.
Security (power system)	The ability of the system to handle a contingent event. 'n-security' describes the state of having a single point of failure before an event occurs.

APPENDIX B: SYSTEM OPERATOR PRELIMINARY REPORT

March 2017 South Island AUFLS Event Preliminary Report

Transpower New Zealand Limited
March 2017

Keeping the energy flowing




TRANSPOWER

IMPORTANT

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Executive Summary

This report is an early summary of events which occurred on 2 March which resulted in an under-frequency event in the North and South Islands and a separation and re-synchronisation of the South Island power system.

This preliminary report details the chain of events and steps taken to restore the power system to normal operation. In the coming weeks Transpower will investigate and report on the circumstances that caused the event and review its management of the response.

On 2 March 2017 at 11:20 the two Clyde-Cromwell-Twizel 220 kV circuits connecting the lower and upper South Island disconnected from the grid in quick succession. The third circuit normally connecting the upper and lower South Island generation was out of service for planned maintenance. The disconnection created two electrical systems in the South Island:

- the Otago/Southland region, including generation at Manapouri, Clyde and Roxburgh and the Tiwai Point smelter load
- the remainder of the South Island, from the Waitaki Valley northwards including generation in the Waitaki Valley, the HVDC connection to the North Island and Canterbury, Nelson and the West Coast.

On disconnection there was a loss of 410 MW of transfer into the upper South Island from the lower South Island. As a result, in the lower South Island system frequency reached 53.6Hz before operation of over frequency protection and generator governor action reduced frequency to a manageable level. In the upper South Island system frequency fell to 47.7Hz tripping the first tranche of automatic under frequency load shedding (AUFLS) relays and reducing load by around 16% or approximately 120MW across the upper South Island.

The HVDC Frequency Keeping Control (FKC) resulted in an automatic 250 MW reduction in HVDC transfer and North Island frequency fell to 49.2 Hz, tripping approximately 396 MW of contracted interruptible load.

The two electrical systems were re-connected at 11:44. Initial data shows the two islands were re-connected when the difference in voltage phase angle across the closing breaker was approximately 60 degrees at the time of closing.

Load restoration instructions from Transpower to South Island distributors were then progressively given and completed by 12:32, seventy-two minutes after the event occurred. Restoration of North Island interruptible load commenced at 11:52.

The event had a marked impact on wholesale energy prices across the country due to the drop in load, with prices falling in response. Prices returned to normal levels after load was restored.

CONTENTS

GLOSSARY

AUFLS	Automatic Under-Frequency Load Shedding; a system by which load is automatically switched off if frequency falls to a given frequency.
Contingent Event (CE)	An event deemed likely enough to occur that instantaneous reserve is procured to maintain frequency above 48 Hz.
Extended Contingent Event (ECE)	An event less likely than a CE, for which instantaneous reserve and AUFLS are used to keep frequency above 47 Hz in the North Island and 45 Hz in the South Island.
Frequency Keeping Control (FKC)	A part of the HVDC link control system which ties the frequency of the North and South Islands, allowing reserve response in one island to maintain frequency in the other.
Grid Emergency	A state of operation where an event requires urgent action from participants to alleviate the situation.
Instantaneous Reserve (IR)	Back-up generation or interruptible load procured and dispatched in order to mitigate the risk of a credible under frequency event.
Interruptible Load (IL)	A form of instantaneous reserve by which load is switched off automatically if frequency falls below 49.2 Hz.
Island (electrical)	A separate power system consisting of generation and load, disconnected from the rest of the grid.
National Co-ordination Centre (NCC)	National Co-ordination Centre, the central point of control for the power system.
National Grid Operating Centre (NGOC)	National Grid Operating Centre, the central point from which Transpower's grid assets are operated.
Other Event	An event which has been assessed as possible to occur but too costly to mitigate.
Phase angle difference	A measure of the synchronism of the AC voltages between two electrical systems.
Protection (electrical)	A type of automatic control system which switches out equipment on the grid in response to faults.

1 REPORT OBJECTIVE

On 2 March 2017 at 11:20 an event occurred on the power system which resulted in the South Island being split into two separate electrical systems. The event saw both low and high system frequencies, a South Island AUFLS operation and an instantaneous reserve (IR) response in the North Island.

This report describes the power system conditions immediately prior to and during the event and the sequence of actions taken in response to the event which led to restoration of normal operation just over an hour later.

Investigations of a number of aspects relevant to and contributing to the event are about to commence. The scope of the review is currently being agreed and will be published shortly.

1.1 INTENDED AUDIENCE

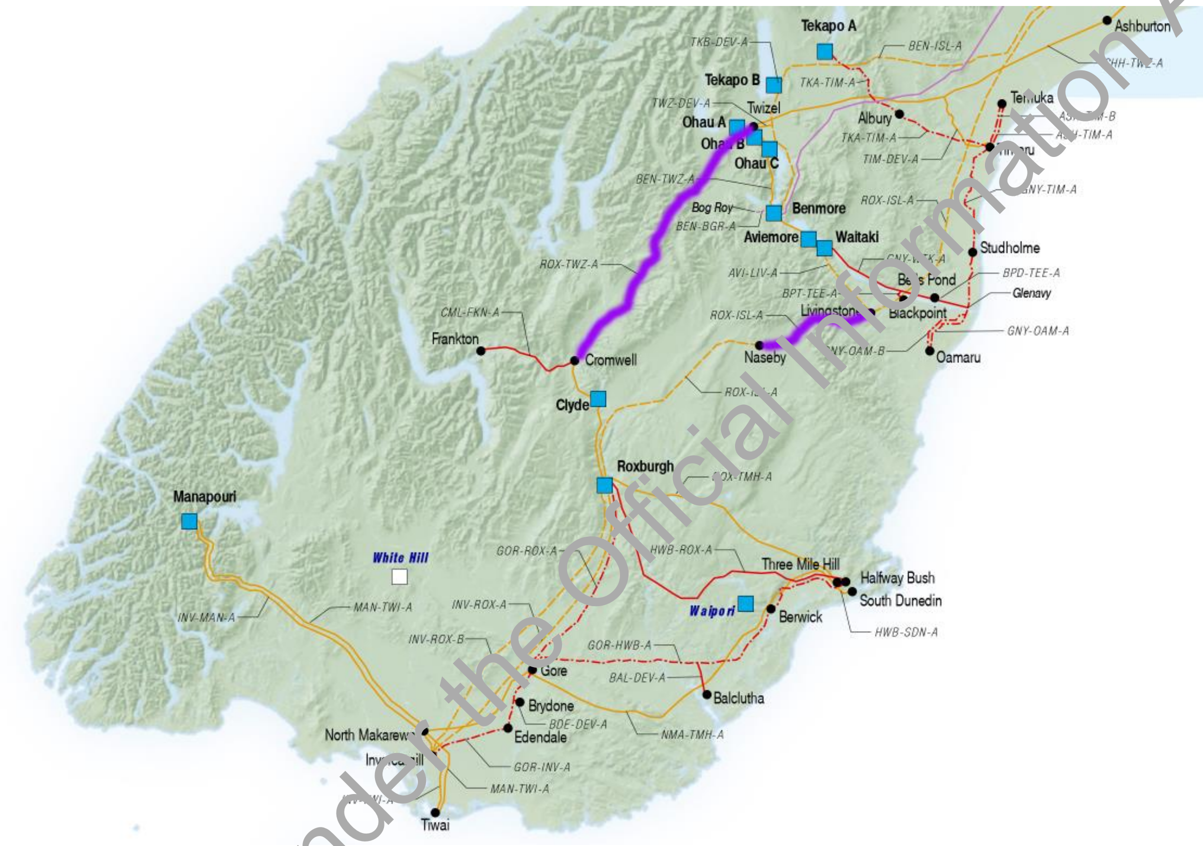
This report is intended for an audience familiar with the structure and operation of the New Zealand power system.

2 Pre-event System Conditions

2.1 Background

2.1.1 South Island Core Grid

The South Island core grid consists of two major groups of generation in geographically separated areas connected by three 220 kV transmission circuits: The Clyde-Cromwell-Twizel 1 and 2 circuits on a common tower and a single Livingston-Naseby circuit on an alternate route. A line diagram of the system is in Appendix A.



2.1.2 Policy for managing events

Transpower, as system operator, identifies credible events which could occur on the power system that would threaten its ability to meet the Principal Performance Obligations[1]. The loss of any one circuit is identified as a Contingent Event (CE); consequently, Transpower ensures there is sufficient transmission capacity or energy reserves available to prevent post-event overload of assets which could lead to a cascading failure.

IR is relied upon to ensure loss of the largest contingent event risk will not cause frequency to fall below 48 Hz. AUFLS and IR are relied upon to ensure loss of the largest Extended Continent Event (ECE) will not cause the frequency to fall below 47 Hz in the North Island and 45 Hz in the South Island. Other

[1] Detailed in clauses 7.2A – 7.2D inclusive in the Electricity Industry Participation Code. These obligations include avoiding cascade failure of assets, maintaining frequency within the normal band and procuring instantaneous reserve to mitigate the effects of contingent and extended contingent events.

Events are considered to have low enough probability the risk is not cost-effective to manage, or for which no feasible controls exist (beyond use of IR AUFLS already in place).

2.1.3 Instantaneous Reserve and AUFLS

The loss of a single circuit is considered a CE. The simultaneous loss of two circuits (as occurred in the event under review) is considered an Other Event. In the South Island the typical quantity of IR scheduled is 125 MW.

Since October 2014 the HVDC FKC control has been used in normal operation. The FKC control varies the HVDC by up to 250 MW to match the two system frequencies in the North and South Islands. This allows IR to be procured in one island to meet the reserve requirements of the other, through rapid modulation of the HVDC link transfer. The effect of this approach to system management is that an event in one island will cause a frequency deviation to be observed in both islands.

2.1.4 Over frequency reserve

To mitigate the risk of a high frequency following a loss of load or the HVDC link, Transpower procures over frequency reserve (OFR). OFR is armed on an as-needed basis.

2.1.5 Re-synchronisation

The loss of circuits connecting one part of the grid to the another can result in formation of an electrical island isolated from the rest of the grid. If the loss is unexpected, a frequency disturbance can occur in both the island and the grid, causing the two frequencies to deviate from one another. Reconnecting the island to the rest of the grid requires closely matching the two frequencies by varying generation output prior to re-synchronisation and then closing a circuit breaker between the two islands when the phase angle difference is close to zero degrees. Transpower has recently installed an automated re-synchronising system in the South Island to aid the synchronisation process by reducing delay from reliance on manual re-synchronisation at substations.

2.2 Generation and Load Conditions

Immediately prior to the event South Island load was 1,980 MW. North Island load was 3,420 MW. South Island load was distributed with 975 MW of load taken from Twizel and Livingston north (the island separation points during the event).

South Island generation totalled 2,800 MW, meeting South Island load and exporting approximately 820 MW northward over the HVDC link. The Manapouri, Clutha and Waipori hydro schemes (south of the island separation point created in the event) were generating 1,345 MW with the balance supplied by the Waitaki and Tekapo schemes, and smaller hydro and wind stations distributed throughout the South Island. Approximately 460 MW was being transferred northward from Clyde on the Clyde-Cromwell-Twizel circuits at the time of the event (410 MW received at Twizel).

The scheduled risk in the South Island was 125 MW. This set the IR requirement. 99 MW of sustained instantaneous reserve (SIR) were dispatched in the South Island with the balance met by North Island reserves. 258 MW of SIR were dispatched in the North Island, of which 204 MW was interruptible load (IL).

2.3 Operational Conditions

Two Clyde-Cromwell-Twizel 220 kV circuits and the Livingston-Naseby 1 220 kV circuit provide the connection between the upper South Island (which includes the Waitaki generation scheme and a large proportion of South Island load) with the lower South Island (an area usually providing a surplus of generation).

At the time of the event the Livingston-Naseby 1 circuit was removed from service for planned maintenance. At the same time, planned protection maintenance was underway at Clyde station, affecting the Clyde termination of the Clyde-Cromwell-Twizel circuits. The work being undertaken at the time of the event was scheduled maintenance, requiring diagnostic inspection and service of the Clyde 220 kV bus coupler and bus zone protection scheme. This work necessitated outages of both the Clyde 220 kV bus zone and circuit breaker fail protection.

Operationally it is normal practice for these functional tests to be carried out with associated grid equipment in service. Therefore, no concurrency clash was identified during the scheduling of these outages and the National Co-ordination Centre (NCC) gave permission for the concurrent outages to proceed.

3 Event and Restoration

On 2 March 2017 at 11:20 the two Clyde-Cromwell-Twizel 220 kV circuits connecting the lower and upper South Island disconnected from the grid in quick succession, during planned maintenance affecting a third circuit that normally connects upper and lower South Island generation. The disconnection created two electrical systems in the South Island:

- the Otago/Southland region including generation at Manapouri, Clyde and Roxburgh and the Tiwai Point smelter load
- the remainder of the South Island, from the Waitaki Valley northwards including generation in the Waitaki Valley, the HVDC connection to the North Island and Canterbury, Nelson and the West Coast.

In the lower South Island system frequency reached 53.6 Hz before operation of over frequency protection and generator governor action reduced frequency to a manageable level. In the upper South Island system frequency fell to 47.4 Hz, tripping the first tranche of AUFLS relays and reducing load by around 16%.

The HVDC FKC meant North Island frequency fell to 49.2 Hz, tripping approximately 396 MW of interruptible load (as expected).

Immediately on separation with the loss of 410 MW of transfer into Twizel the lower South Island had excess generation; the upper South Island excess load. Automatic power system control systems operated to prevent a blackout in either electrical system arising from these generation and load imbalances.

In the lower South Island, excess generation was tripped off. In the upper South Island, HVDC export to the North Island automatically pulled back by 250 MW and under frequency load shedding (AUFLS) reduced upper South Island load supplied across Transpower's substations by 16% or approximately 120 MW.

The two systems were subsequently reconnected (re-synchronised) at 11:44 am and by 12:01 pm distribution companies had been instructed to reconnect all load shed by AUFLS. All consumers were able to have power restored by around 12:30 pm

This is a significant power system event. There is no recent record in New Zealand of a similar successful separation of a major part of the power system.

3.1 Timeline of Events

11:20	Clyde-Cromwell-Twizel 2 circuit trips at Twizel. Subsequently, the parallel Clyde-Cromwell-Twizel 1 circuit trips, disconnecting the lower South Island from the upper South Island. During planned maintenance and testing of the Clyde 220 kV bus zone and CB fail protection a protection inter-trip signal was unexpectedly sent to Twizel tripping the Twizel end of the Clyde-Cromwell-Twizel circuits 1 and 2.
11:21	Disconnecting generation from load causes system frequency to drop in the upper South Island to 47.4 Hz and to rise in the lower South Island to 53.6 Hz. The HVDC FKC control reacts to the low frequency in the upper South Island by reducing HVDC transfer north to 576 MW (from 826 MW dispatched). The reduction results in a fall of North Island frequency to just below 49.2 Hz Reserve generation and interruptible load triggers in both the upper South Island and North Island, including 16% of upper South Island load controlled under AUFLS

	(approximately 120 MW). 396 MW of North Island load are tripped in response to the under-frequency event. Generators in the lower South Island either trip (from operation of Over Frequency Arming relays) or ramp down output in response to rapidly increasing system frequency.
11:27	Generators are assigned to manage frequency keeping in the lower and upper South Island.
11:28	A Grid Emergency is (verbally) declared to reconfigure the grid to reconnect (re-synchronise) the two electrical islands formed and allow restoration of load.
11:29	National frequency keeping is deactivated and reversion made to island frequency keeping mode (two frequency keepers selected for each electrical island in the South Island).
11:30	NCC instructs National Grid Operating Centre (NGOC) to prepare for re-synchronising at Clyde station, using Clyde-Cromwell-Twizel 1 circuit.
11:43	Initial attempt to re-synchronise fails.
11:44	Subsequent attempt to re-synchronise succeeds, re-connecting the two electrical islands in the South Island. Initial data shows the two islands were connected when the island frequencies were different by 0.6 Hz and the angle across the closing breaker was approximately 60 degrees at the time of closing. This is being assessed further and will be more accurately reported as part of the wider investigation.
11:46	Clyde-Cromwell-Twizel 2 circuit restored.
11:48	South Island now one complete and stable system, with Manapouri keeping frequency.
11:52	NCC begins instructing North Island IL providers to restore load.
12:01	NCC begins instructing South Island distributors to restore AUFLS load.
12:32	Grid emergency ends with all load able to be restored.

3.2 Power System Response

The power system response to the trippings and creation of electrical islands worked broadly as designed and expected. The increase in system frequency in the lower South Island (due to termination of generation load transported from the lower south) was met by over frequency armed generators and also by governor action. Sudden loss of import into Twizel (from the lower south) in the upper South Island was managed by HVDC FKC action (which reduced transfer across the HVDC) and by load shedding (North Island) and AUFLS arrangements (upper South Island).

FKC action resulted in the expected frequency fall in the North Island, generating an expected response from scheduled IL providers. Although 204 MW of North Island IL was dispatched, almost 400 MW responded. This is because IL is generally armed to trip regardless of dispatch instruction.

Figures 1 and 2 show the frequency response in the South Island and North Island to the event. The South Island chart is plotted using phasor measurements unit readings at Twizel (TWZ) and Roxburgh (ROX), reflecting the frequencies of each of the electrical islands that formed.

In the Upper South Island system there was a second fall in frequency which reached a low of 48.52 Hz about 5 minutes after the event. This was due to an unexpected reduction in power at the Aviemore generation station. The cause of the reduction has been identified and rectified.

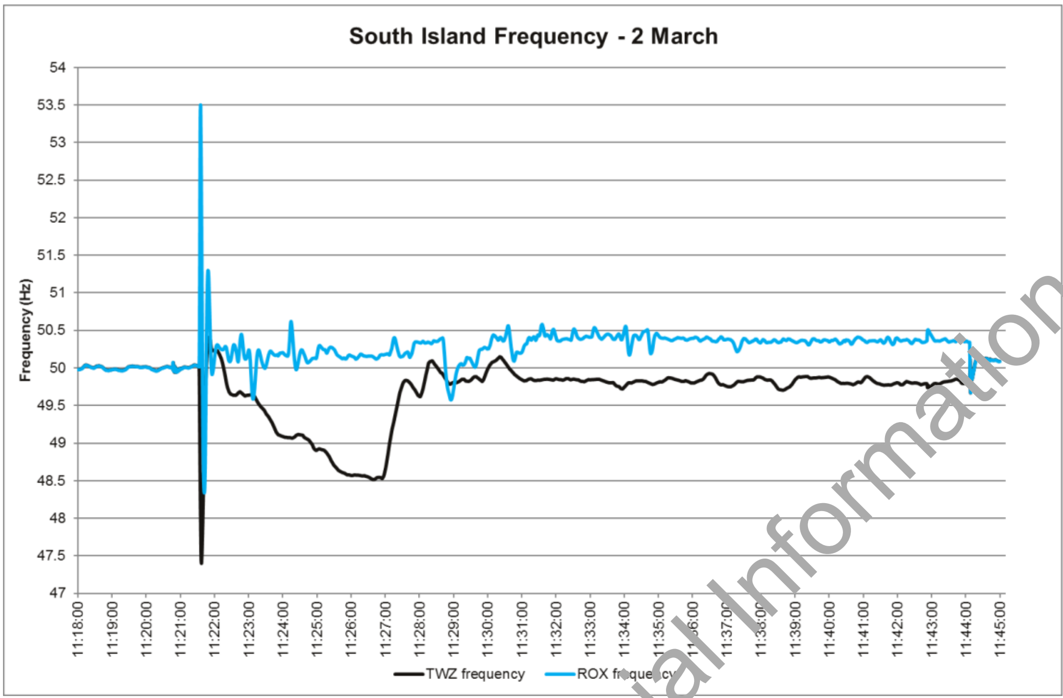


Figure 1 – South Island frequency from two minutes pre event until re-synchronisation.

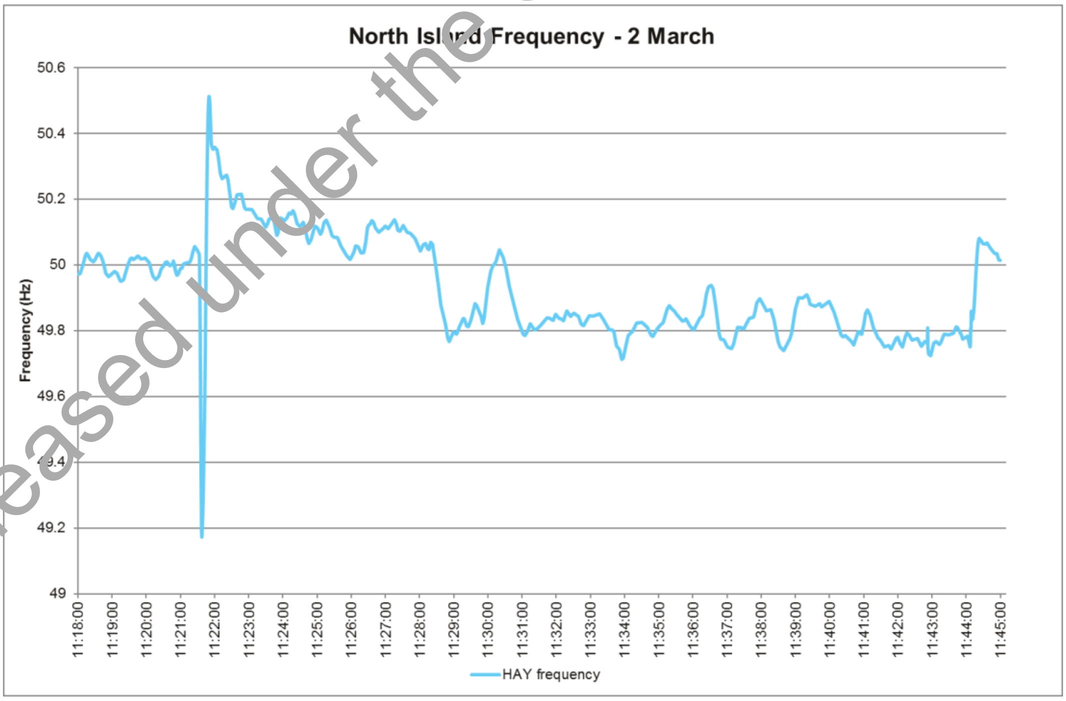


Figure 2 – North Island frequency for the same period.

3.3 SOUTH ISLAND RE-SYNCHRONISATION

In order to restore all load, Southland generation needed to be reconnected to the rest of the country. This required returning the Clyde-Cromwell-Twizel circuits to service and re-synchronising the two electrical islands which had formed. Two attempts at re-synchronisation were made. For the second (successful) attempt the phase angle difference between the two electrical islands was approximately 60 degrees. This angle represents the extent to which the electrical islands were out of phase with one another at reconnection. This difference is unusually high and Transpower will investigate the re-synchronisation process.

3.4 MARKET IMPACT

In the North island, interruptible load operated in response to the under frequency event. AUFLS operated in the upper South Island. Each combined to materially reduce national load (shown in Figure 3). The unexpected lower load caused prices to fall sharply, by approximately $50 per MWh. Prices gradually increased as load was restored in stages, returning to normal by the 13:00 trading period.

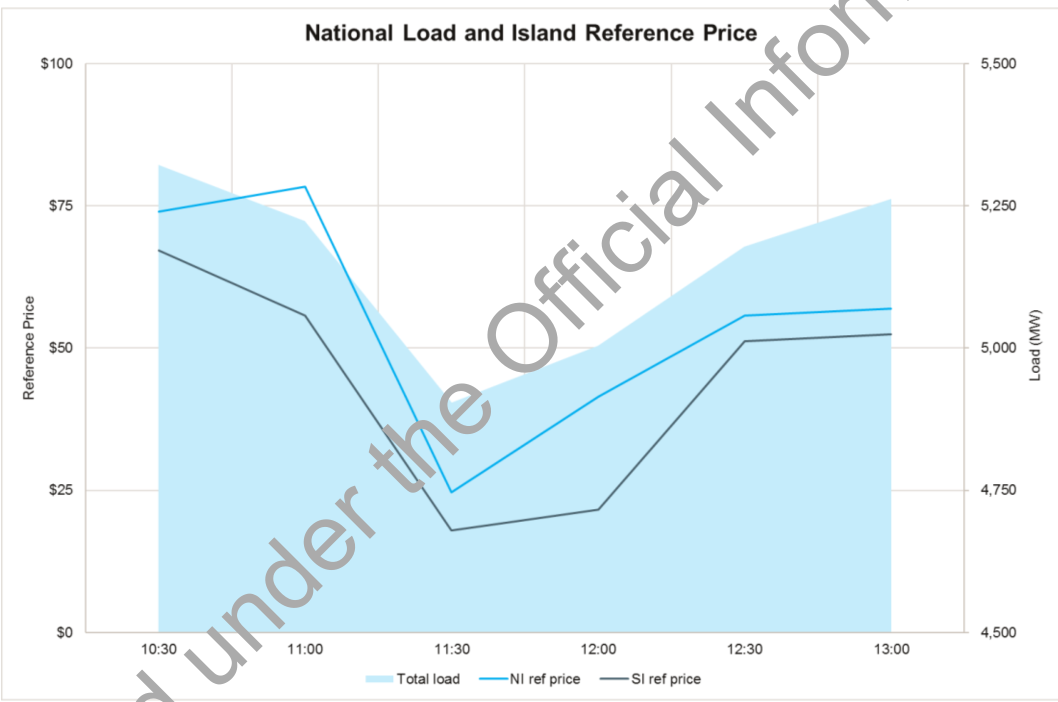
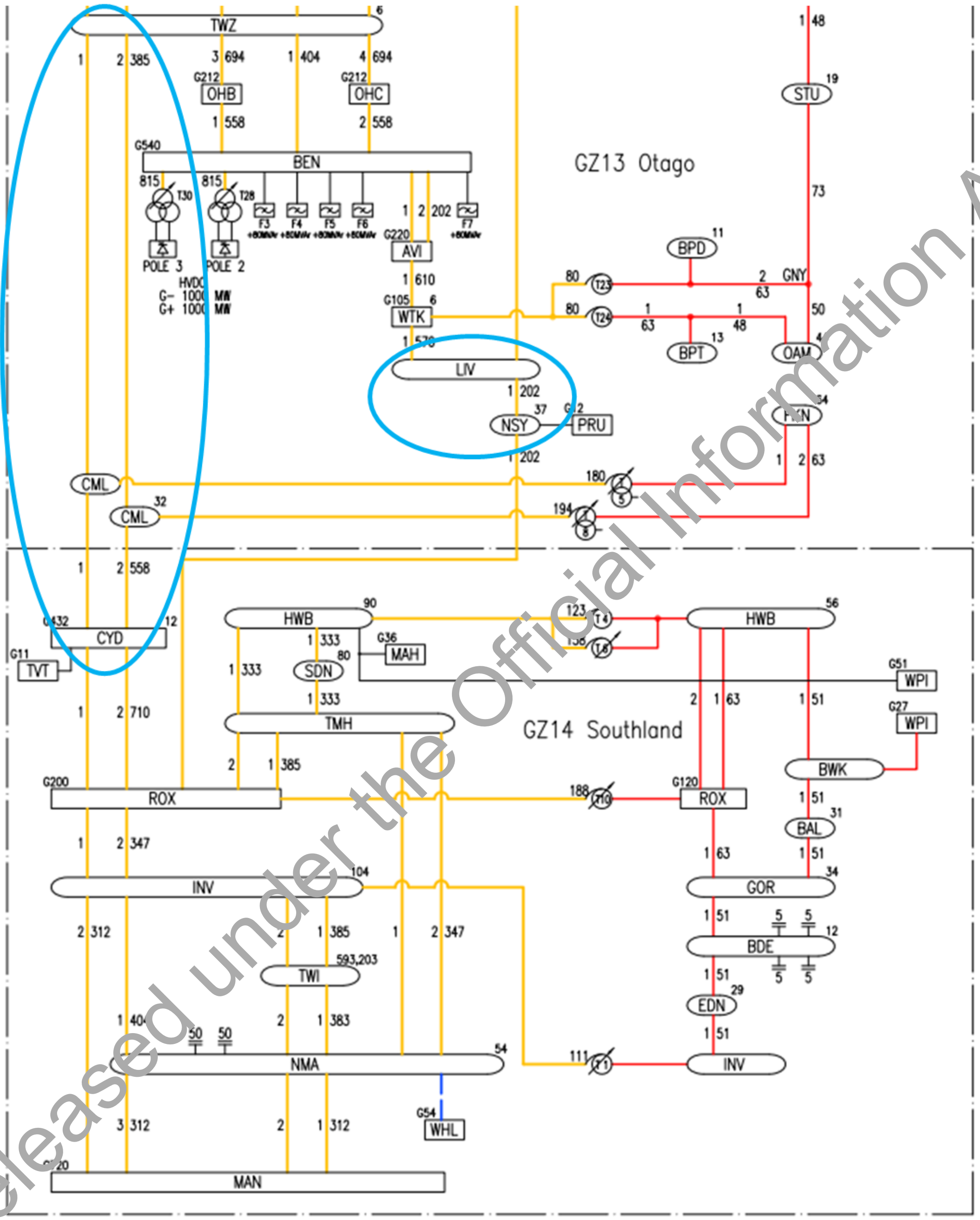


Figure 3 – National load drop and island reference price effects

Appendix A – Lower South Island Power System



APPENDIX C: SYSTEM IMPACT REPORT - PSC

Specialist Consultants
to the Electricity Industry

Investigation into the System Response to Splitting the South Island Grid and Subsequent Attempts to Re-Synchronize on 2 March 2017

Prepared by	**Ranil de Silva** **Director of Engineering** **Power Systems Consultants**
For	**Transpower New Zealand Ltd**
Reference	**J06520 – Final Report**
Date	**19 April 2018**

List of Revisions

Revision	Date	Description
Final Report	19 April 2018	• Final report

Reviewers

Name	Interest	Signature	Date
Tim Browne	Peer Review		20 April 2018

Approval

Name	Interest	Signature	Date
Tim Browne	General Manager – Power Networks		20 April 2018

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Executive Summary

On Thursday 2nd March 2017, protection maintenance work was being carried out on the Clyde 220 kV bus at the same time as a maintenance outage on the Livingstone-Naseby 220 kV circuit, leaving the upper and lower South Island grid being connected only by the Clyde-Cromwell-Twizel 220 kV double circuit line. At 11:20 Clyde-Cromwell-Twizel 220 kV Circuit 2 tripped during protection testing, and 46 seconds later at 11:21 Clyde-Cromwell-Twizel 220 kV Circuit 1 also tripped during protection testing. This resulted in a major disturbance with the South Island grid being split into a 'Lower South Island' and an 'Upper South Island'. Disturbances to connected parties included

- an over-frequency and 3 generators tripping in the Lower South Island,
- under-frequency in the Upper South Island, and
- under-frequency in the North Island.

120 MW of AUFLS Zone 1 load was tripped in the Upper South Island and about 350 MW of contracted interruptible load was tripped in the North Island.

About 21 minutes after the split, at 11:42, an attempt was made to re-synchronize the Upper and Lower South Island networks via a Clyde-Cromwell-Twizel 220 kV circuit (this attempt was made even though there was confusion on the procedure for resynchronization and the reason for the original tripping was still unclear). This failed with an out-of-phase re-synchronization and subsequent circuit trip resulting in a second major disturbance. About 2 minutes later, at 11:44, another re-synchronization attempt was made which was also out-of-phase and caused a third disturbance, however this time the grid remained connected.

Transpower initiated an investigation into the circumstances leading up to the disturbances, including contracting PSC to carry out an independent review.

The incident highlighted a variety of issues. In PSC's opinion, the split was the end consequence of a chain of three independent and unrelated problems :

1) Not adhering to the philosophy of 'Security and Maintainability by Design' for the 220 kV protection at Clyde.

2) Insufficient consideration in the outage planning process around the risks associated with maintenance on 220 kV protection at Clyde during high power transfers from the Lower South Island to Upper South Island.

3) A lack of situational awareness by technicians working on the 220 kV protection at Clyde.

If any one of these problems had not been present then this particular incident would likely not have occurred.

After the split, the resynchronization of the South Island revealed issues with NCC and NGOC understanding of policy around returning circuits to service as well as their training on the auto-synchronization scheme.

Transpower has carried out simulations of the re-synchronizations which suggest that the transient electrical torques applied to South Island generators during the re-synchronizations were comparable to the transient electrical torques that would be expected for a 3 phase bus fault at the generators' 220 kV points of connection. The simulations also suggest that the impedance of the long Clyde-Cromwell-Twizel 220 kV circuit helped to reduce the transient torques.

Having completed this investigation, PSC has the following recommendations :

1) Emphasize Protection Security and Maintainability by Design

PSC recommends that Transpower's Protection and Automation Team uses this incident to emphasize the philosophy of Security and Maintainability by Design. Specifically, the need for providing practical methods for isolating protection relay outputs, and providing clear documentation of protection signal paths (we note that Transpower has already published a 'Quality Alert' on this topic).

2) Consider N-2 Contingencies in the Outage Planning Process

PSC recommends that Transpower's outage planning process considers the effect of N-2 contingencies when there is a heightened risk associated with protection maintenance work.

With respect to outage planning on the Clyde-Cromwell-Clyde 220 kV circuits, possible mitigations could include :

- Carrying out the maintenance at reduced levels of transfer from the Lower to Upper South Island so that a double circuit tripping would not overload and trip the remaining Roxburgh-Naseby-Livingstone 220 kV circuit.
- Dispatching extra spinning reserve in the Upper South Island or North island so that AUFLS load is not shed in the event of a double circuit tripping.
- Planning for re-synchronization of the Lower and Upper South Island in the event of a double circuit tripping.

3) Improve Situational Awareness for Protection Work

PSC recommends that Transpower considers improving the situational awareness of technicians carrying out protection maintenance. One possibility is to give the technicians access to Near Real Time SCADA on a laptop to let them observe the operation of the local network.

4) Rectify Problem with Aviemore Runback

PSC recommends that Meridian rectify the incorrect settings in the Aviemore generator runback. (We note that Meridian have already rectified this problem).

5) Training on Policy on Restoring Circuits to Service

PSC recommends that NCC and NGOC review training on Transpower's policy on 'Circuit Tripping Response Management', particularly with respect to restoring circuits only when the reason for tripping is understood. The training might use this particular incident as an example of errors that can be made when working under pressure.

6) Training on Auto-Synchronization

PSC recommends that more frequent training is provided on auto-synchronization at both NCC and NGOC using the training simulator. The simulator should be able to simulate the time required for the process (up to 5 minutes before timing out), and simulate the impacts of a good and bad synchronization.

PSC also recommends that Transpower ensures training is provided to operators who may have to use manual synchronization with synchroscopes as a backup to the auto-synchronization.

1. Introduction

On Thursday 2nd March 2017, protection maintenance work was being carried out on the Clyde 220 kV bus at the same time as a maintenance outage on the Livingstone-Naseby 220 kV circuit, resulting in the upper and lower South Island grid being connected only by the Clyde-Cromwell-Twizel 220 kV double circuit line. At 11:20 Clyde-Cromwell-Twizel 220 kV Circuit 2 tripped during protection testing, and 46 sec later at 11:21 Clyde-Cromwell-Twizel 220 kV Circuit 1 also tripped during protection testing. This resulted in a major disturbance with the South Island grid being split into a 'Lower South Island' and an 'Upper South Island'. Disturbances to connected parties included an over-frequency and 3 generators tripping in the Lower South Island, under-frequency in the Upper South Island, and under-frequency in the North Island. 120 MW of AUFLS Zone 1 load was tripped in the Upper South Island and about 350 MW of contracted interruptible load was tripped in the North Island.

About 21 minutes after the split, at 11:42, an attempt was made to re-synchronize the Upper and Lower South Island networks via a Clyde-Cromwell-Twizel 220 kV circuit. This failed with an out-of-phase re-synchronization and subsequent circuit trip resulting in a second major disturbance. About 2 minutes later, at 11:44, another re-synchronization attempt was made which was also out-of-phase and caused a third disturbance, however this time the grid remained connected.

Transpower initiated an investigation into the circumstances leading up to the disturbances as well as the organizational and system responses to the disturbances. As part of this investigation, Transpower contracted PSC to carry out an independent review of the incident.

2. Scope of Work

PSC's detailed scope of work is included in Appendix 1 and the credentials of the author are described in Appendix 2. In brief, the scope was to independently review the incident by carrying out a 'Desktop Investigation'. A desktop investigation is typically an initial limited cost investigation based on reviewing reports and some relatively simple hand calculations (it does not include detailed calculations or modelling).

The scope included :

1) Reviewing the system response to the splitting of the grid and subsequent attempts at resynchronization
2) Reviewing and discussing Transpower's reports on the incident from :
    a. System Operator National Control Centre (NCC)
    b. Transpower National Grid Operating Centre (NGOC)
    c. Transpower Protection and Automation
3) Reviewing and providing guidance on Transpower's modelling of disturbances

Appendix 3 lists the discussions held between the reviewer and Transpower employees.

3. Description of the Incident

3.1. Clyde Protection Upgrade in 2015

2 years prior to this incident, in 2015, the Clyde 220 kV protection was upgraded to install circuit breaker fail inter-trips on the Clyde – Cromwell – Twizel 220 kV circuits. The inter-trips were designed to rapidly trip the remote Twizel circuit breakers in the event of a 220 kV bus fault and circuit breaker failure at Clyde [1,2,3] .

Transpower does not normally install circuit breaker fail inter-trip schemes (on most circuits, the fault current that continues to flow through an open circuit breaker into a bus fault is eventually interrupted by the remote end circuit breaker tripping on Zone 2 distance protection). Also, Transpower does not have one standard design for circuit breaker fail inter-trip schemes. Different practices have been followed where these schemes have been installed in the grid. The rationale for installing the circuit breaker inter-trip scheme in this case was to minimize the duration of a 220 kV bus fault at Clyde because it is a GIS (Gas Insulated Switchgear) bus and more difficult and more expensive to repair than the more common AIS (Air Insulated Switchgear) buses in the rest of the network.

The source of the inter-trip signal is the circuit breaker fail timer relay. Prior to the upgrade, the output signal from this relay passed through a service/test switch before being distributed to the rest of the protection system. The relay's timing could

[1] Transpower Protection Report
[2] Transpower Quality Alert
[3] Discussion with Transpower Protection and Automation Manager

be tested by first setting the service/test switch to 'test' (which isolated the output signal) and then energizing the relay coil to check its time delay.

The inter-trip scheme installed during the upgrade bypassed the service/test switch and passed through an auxiliary relay. The remaining methods of disabling the inter-trip were not considered to be standard or desirable :

a) Physically disconnect the relay output wiring or auxiliary relay (which would interfere with wiring).
b) Disabling Line Protection 1 and 2 which carry the inter-trip signal to Twizel (which would degrade the ability of the protection system to detect a line fault).
c) Use SCADA to disable the inter-trip receive at Twizel (which is not considered to be reliable for protection maintenance).

In addition, the bypass of the service/test switch was made more problematic because the protection documentation and drawings did not clearly describe the signal paths used by the inter-trip.

3.2. Network Maintenance and Outages Prior to the Incident

Figures 1,2, and 3 show the South Island network just prior to the system split from a geographical viewpoint, single line diagram, and three island representation.

On a typical day, Transpower coordinates multiple planned maintenance activities and outages scattered around the network. On 2 March 2017 there were two activities that were pertinent to the incident. Transpower's outage planning process had scheduled both activities on the same day and both NCC [4] and NGOC [5] were aware of both activities :

1) The Livingstone – Naseby 220 kV circuit was out of service for maintenance.
2) Protection technicians were working on the Clyde 220 kV bus protection and circuit breaker fail protection.

As a result of the Livingstone – Naseby circuit outage, the South Island network consisted of an Upper South Island network and Lower South Island network

[4] The Transpower System Operator's National Control Centres (NCC) in Hamilton and Wellington are responsible for overall system control, dispatching generation under market rules and ensuring system security. If any network switching is required then the NCC Security Coordinator will instruct NGOC to carry out the switching operations.
[5] Transpower's National Grid Operating Centres (NGOC) in Auckland and Christchurch are responsible for operating Transpower's assets including substations and transmission lines. The NGOC Grid Asset Controller will advise NCC what assets are available for service.

connected by the Clyde – Cromwell – Twizel 220 kV double circuit line. This line was transmitting a total of 426 MW from the Lower South Island to the Upper South Island, which represented 31 % of the Lower South Island generation and 23 % of the Upper South Island demand (including the HVDC transfer of 812 MW to the North island).

The 2 protection technicians working on the Clyde 220 kV busbar and circuit breaker fail protections had helped prepare the isolation and test procedure about 1 month earlier together with a 3rd technician. All 3 technicians failed to recognize that the service/test switch on the circuit breaker fail timer relay did not isolate the inter-trips to Twizel.

Figure 1. Geographical View of System Split

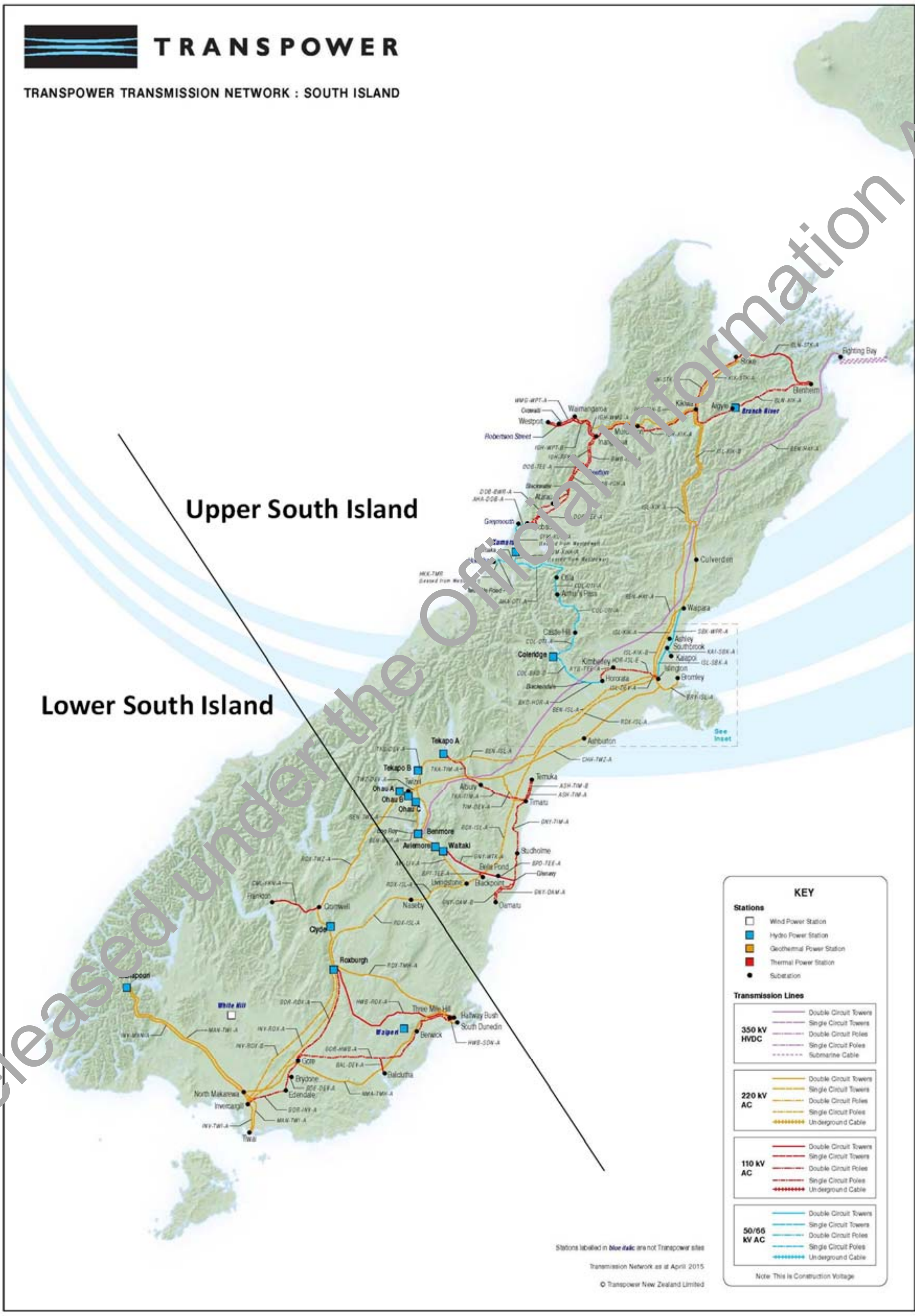


Figure 2. Single Line Diagram with System Split

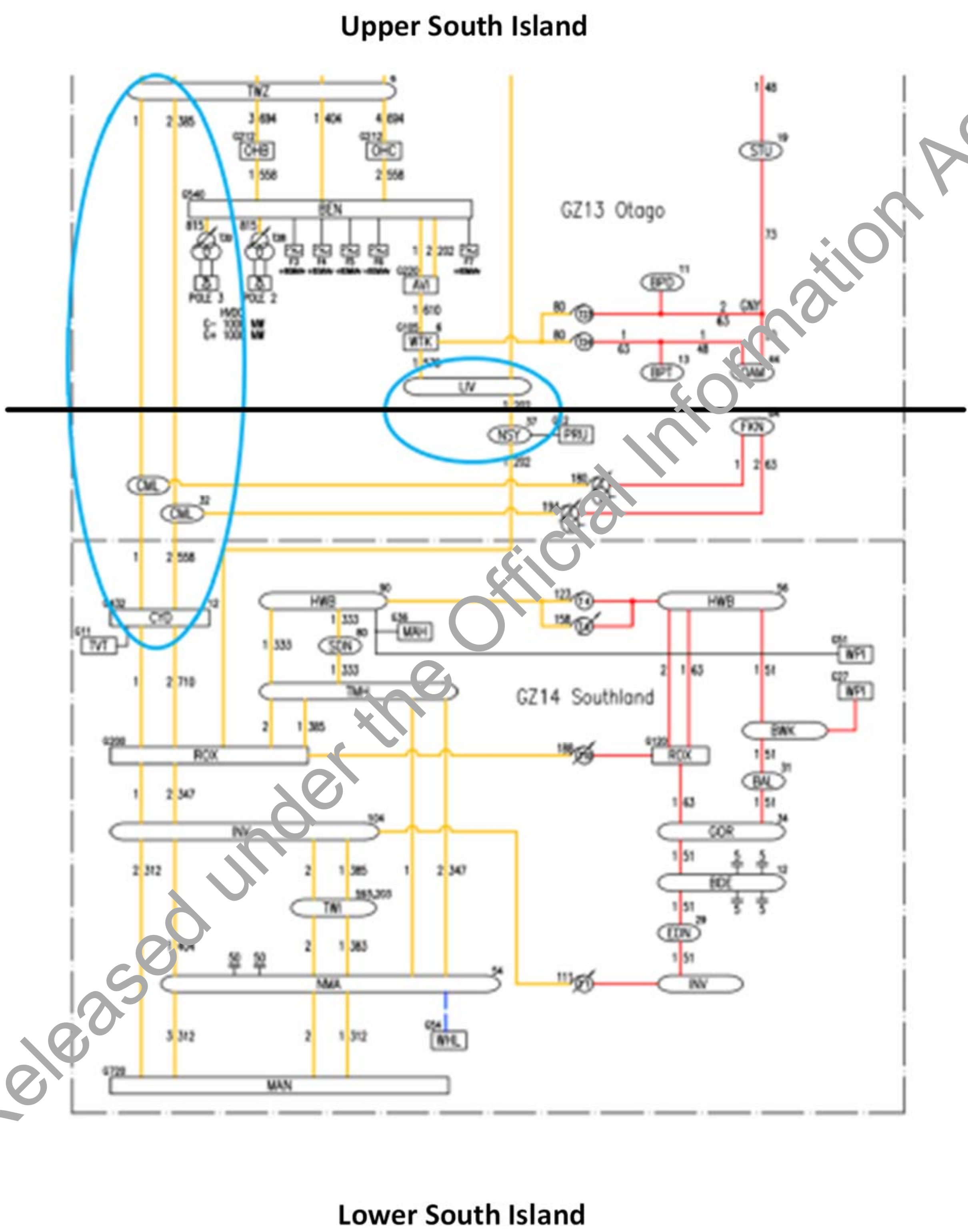
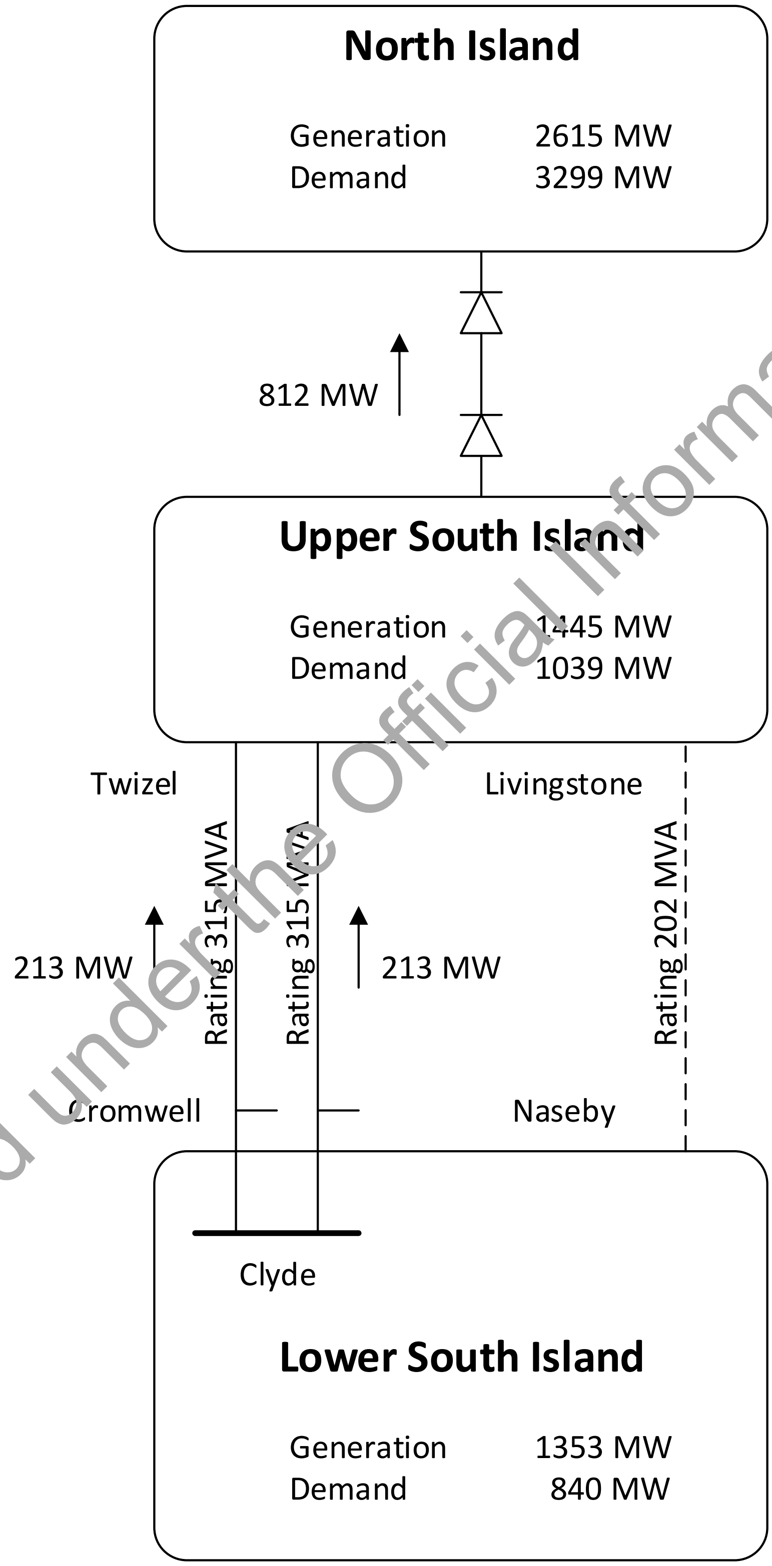


Figure 3. Three Island Representation of System Split



3.3. Network Splitting

Table 1 shows a timeline of the incident from the first circuit tripping until all load was restored.

The protection technicians at Clyde set the service/test switch on the Clyde – Cromwell – Twizel 2 circuit breaker fail timer relay to 'test' and at 11:20:45 they test energized the relay coil. The inter-trip signal bypassed the service/test switch and was transmitted to Twizel, tripping the line breakers. This resulted in the Upper South Island and Lower South Island being connected by only Clyde – Cromwell – Twizel 1. The inter-trip and breaker operation at Twizel was reported on SCADA at both NCC and NGOC. Transpower's Phasor Measurement Units (PMU's) recorded a damped oscillation between the block of generators in the Upper South Island and the block of generators in the Lower South Island. The protection technicians working in the relay room at Clyde were not aware of the inter-trip. They were not in immediate contact with NGOC and the nearest indication would have been on the local SCADA display located in the separate 33 kV control room.

The protection technicians then moved on to testing the circuit breaker fail timer relay on the remaining circuit (located adjacent to the first relay) and 46 seconds after the first trip sent a second inter-trip to Twizel to trip Clyde – Cromwell – Twizel 1. This resulted in the South Island network splitting into a Lower South Island network and an Upper South Island network. The protection technicians were unaware of the split although they did hear the sound change from a Clyde generator when it tripped on over-frequency.

Figure 4A shows the frequency fluctuations in the Upper South Island and Lower South Island. Figure 4B shows the frequency fluctuations in the North Island. The splitting resulted in an excess 426 MW generation in the Lower South Island which was 51 % above the Lower South Island demand. The frequency rapidly rose and was limited to 53.5 Hz by a combination of governor response and over-frequency tripping of 2 generators at Manapouri and 1 generator at Clyde. (The over-frequency tripping scheme is set to 53 Hz and was not designed for this scenario but was intended to limit frequency rise for a tripping of the HVDC bipole.)

The splitting also resulted in a deficit of 426 MW generation in the Upper South Island which was 23 % of the Upper South Island demand (including the HVDC transfer). The frequency rapidly fell and was limited to 47.4 Hz by a combination of governor response, tripping about 120 MW of Zone 1 Automatic Under-frequency Load Shedding (AUFLS) at 47.5 Hz, and a 250 MW reduction in HVDC power transfer due to the action of the HVDC Frequency Keeping Control (FKC) which is limited to a range of +/- 250 MW.

The Upper South Island frequency recovered to about 50 Hz but then started to fall again as the Aviemore generators ran back by about 159 MW. This runback was caused by an incorrect setting in the Aviemore governor controls which was intended to runback for over-frequency rather than under-frequency. The second frequency fall was limited to about 48.5 Hz, probably by governor response.

The 250 MW reduction in HVDC power transfer (8 % of North Island demand) results in an under-frequency in the North Island. This is limited to 49.2 Hz by a combination of governor response and tripping 396 MW of interruptible load. The load tripping exceeds the HVDC power reduction so the under-frequency is followed by an over-frequency of 50.5 Hz, limited by governor response.

Table 1. Timeline for South Island Split and Resynchronization

Actual Time (hh:mm:ss)	Event Time (mm:ss)	Event
11:20:45	- 00:47	• Trip TWZ end of CYD-CML-TWZ 2 • South Island Oscillation
11:21:32	00:00	• Trip TWZ end of CYD-CML-TWZ 1 • Split South Island network <u>Lower South Island</u> • 2xMAN 1xCYD generator over-frequency trip at 53 Hz • Over-frequency peak 53.5 Hz <u>Upper South Island</u> • 120 MW AUFLS Zone 1 47.5 Hz Load shedding • -250 MW by FKC power modulation on HVDC link • 1st under-frequency trough 47.4 Hz <u>North Island</u> • Interruptible load tripping 396 MW • Under-frequency trough 49.17 Hz
11:22:00	00:28	• Aviemore generators runback by 159 MW <u>Upper South Island</u> • 2nd under-frequency trough 48.5 Hz
11:28:00	06:28	• NCC declares a Grid Emergency to NGOC for the purpose of re-synchronizing the Upper and Lower South Islands
11:42:52	21:20	• Failed out-of-phase re-synchronization on CYD-CML-TWZ 1 at CYD • Approx 120 deg out-of-phase • High line current approx 2.8 kA (340% summer rating) • Trip on Zone 1 Distance protection • Disturbance to generators
11:42:53	21:21	• Auto-reclose at TWZ end of line
11:44:06	22:34	• Successful (60 deg out-of-phase) re-synchronization on CYD-CML-TWZ 1 at CYD • Disturbance to generators
11:52:00	30:28	• NCC begins to restore North Island interruptible load
12:01:00	39:28	• NCC begins to restore South Island AUFLS load
12:32:00	70:28	• All load restored • NCC rescinds Grid Emergency

Figure 4A. Frequency Fluctuations in the Upper and Lower South Islands

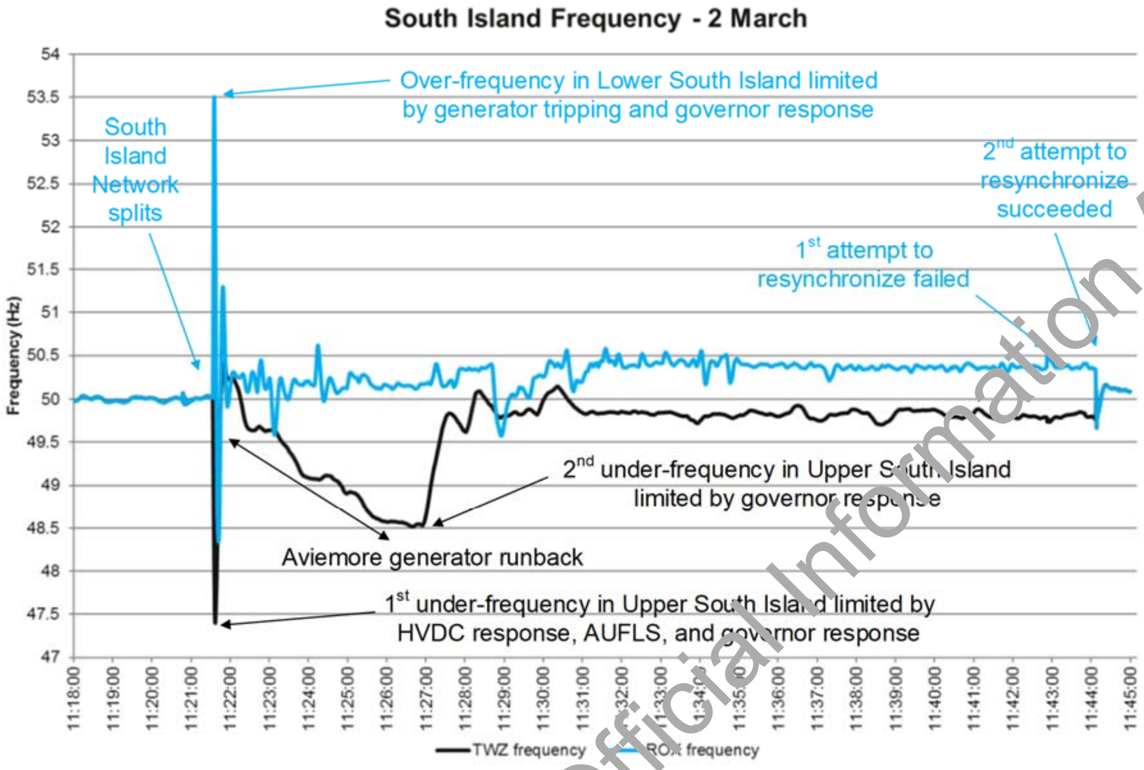
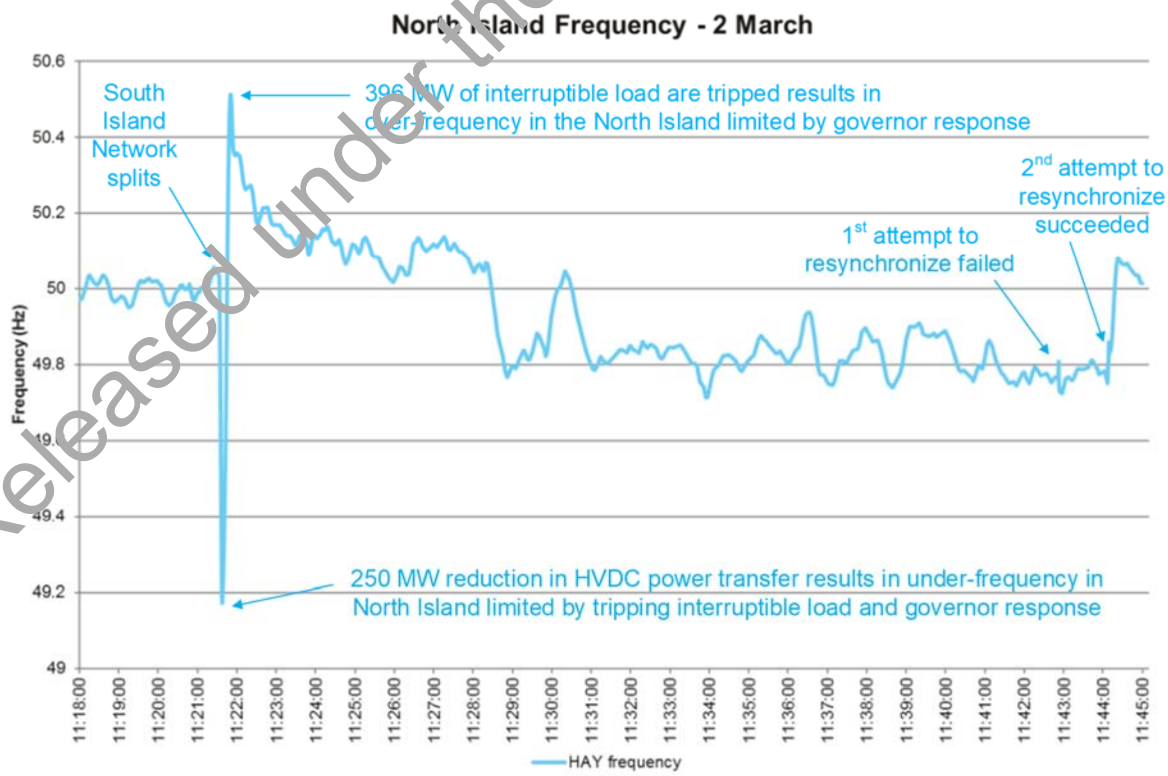


Figure 4B. Frequency Fluctuations in the North Island



3.4. Network Resynchronization

When the split occurred, the work load at both NCC and NGOC increased to an extremely high level as they analysed the situation and fielded calls from parties connected to the network. The last split of the South Island network was in 1993 (involving the same 220 kV circuits) so NCC and NGOC were dealing with an unfamiliar event.

The NCC coordinators reacted to the South Island split by first dispatching generators to stabilize the voltage and frequency in the Lower South Island (high frequency and voltage), Upper South Island (low frequency), and North Island (low frequency). The national Multiple Frequency Keeper (MFK) function was disabled and separate frequency keeping stations were assigned to manage the frequency in each of the three islands.

There was a discussion at NCC about two options for stabilizing the system :

1) Immediately re-synchronize the Upper South Island and Lower South Island to restore normal and secure operation
2) Operate the three islands separately and ensure security in each island, with a view to resynchronizing at a later time

NCC coordinators chose the option to immediately re-synchronize the South Island network. The primary reasons for this appear to be :

1) NCC coordinators believed it would be difficult to dispatch generation in the Upper and Lower South Islands through the market dispatch process. [6]
2) Discussion with NGOC suggested that the Clyde – Cromwell – Twizel circuits were available for service again.

At this stage it appears that the NCC Security Coordinator and NGOC Grid Asset Controller did not have a clear understanding of why the Clyde – Cromwell – Twizel circuits had tripped. Transpower policy states that circuits should not be returned to service unless either the line has been patrolled, or there is a Grid Emergency and the reason for the tripping is understood and it is clear that it is safe to return to service [7]. This suggests that the NGOC Grid Asset Controller should not have made the circuits available to NCC.

NCC and NGOC jointly decided that resynchronization would be carried out by using the auto-synchronizing function on the circuit breaker at the Clyde end of Clyde – Cromwell – Twizel Circuit 1. At 11:28 the NCC Security Coordinator declared a Grid Emergency to the NGOC Grid Asset Controller to allow NGOC to reconfigure the network in preparation for resynchronizing. The reconfiguration included :

[6] Discussion of alternative options in Transpower NCC report
[7] Transpower Response Management Report – Appendix A

1) Disconnecting transformers at Cromwell and Frankton to prevent the 110 kV Tee feed to Frankton becoming a weak link between the Upper and Lower South Islands.
2) Opening the circuit breaker at the Clyde end of Clyde – Cromwell – Twizel Circuit 1, and livening the circuit from Twizel

The NCC Security Coordinator and NGOC Grid Asset Controller discussed the procedure for auto-synchronization. There appeared to be some confusion over the procedure and they do not appear to have looked at the documentation.

At 11:42 the NCC Security Coordinator instructed the NGOC Grid Asset Controller to re-synchronize the Upper and Lower South Island by using the auto-synchronization function on the circuit breaker at the Clyde end of Clyde – Cromwell – Twizel Circuit 1. The auto-synchronization display was visible on SCADA at both NCC and NGOC, however neither realized that the auto-synchronization function was not enabled. The NGOC Grid Asset Controller then used the auto-synchronization display to close the breaker manually in the mistaken belief that this would start the auto-synchronization process.

The records from the line protection and Transpower's Phasor Measurement Units indicate that when the breaker closed, the Upper South Island phase was about 120 degrees ahead of the Lower South Island phase and the Lower South Island frequency was about 0.6 Hz higher than the Upper South Island frequency (this compares with the auto-synchronization settings of maximum 3 degrees and maximum 0.05 Hz for breaker closing). This resulted in a large synchronizing current flowing through the breaker and a low voltage at Clyde. This would have been accompanied by large synchronizing torques being imposed on generators.

Figures 5A and 5B show the measured currents and voltages on the Clyde breaker, and simulated current and voltage from Transpower modelling of the event on DigSilent PowerFactory. The measured currents show a significant DC offset which is expected for both a fault and an out-of-phase synchronization. If the DC offset is removed then the peak measured currents appear to be slightly higher than the simulated positive sequence peak current of 3.2 kA, corresponding to a simulated positive sequence rms current of 2.3 kA . This represents a 340% overload on the summer rating of the circuit. The combination of high current and low voltage resulted in the Zone 1 distance protection tripping both ends of Clyde – Cromwell – Twizel Circuit 1. The current is interrupted in about 50 ms.

The Twizel end circuit breakers auto-reclosed after 1 sec. This suggests another departure from documented procedure which requires auto-reclose to be disabled as part of the auto-synchronization process [8].

It appears that nobody at NCC or NGOC realized that the tripping of the circuit being used for re-synchronization implied that an out-of-phase re-synchronization had occurred along with a severe disturbance. There was further discussion between NCC and NGOC about why the auto-synchronization process seemed to have not completed and about 1 minute after the 1st failed auto-synchronization, the NGOC Grid Asset Controller attempted a 2nd auto-synchronization. Once again the auto-synchronization function was not enabled and the Grid Asset Controller closed the breaker manually.

For the 2nd re-synchronization, Transpower's Phasor Measurement Units indicate that when the breaker closed, the Upper South Island phase was about 60 degrees ahead of the Lower South Island phase and the Lower South Island frequency was about 0.6 Hz higher than the Upper South Island frequency. The reduced phase discrepancy would have resulted in lower synchronizing currents than the 1st re-synchronization and the two islands were synchronized without operating the line protection (consequently there is no record of the synchronizing currents for the 2nd re-synchronization).

After the South Island had been re-synchronized the NCC coordinators proceeded to dispatch generation under market rules, restore interruptible load in the North Island, and restore AUFLS load in the Upper South Island. All load was restored by 12:32 when NCC rescinded the Grid Emergency.

[8] Section 5.4 of Transpower Protection Report.

Figure 5A. 1st Attempt to Re-synchronize – Current in Clyde Circuit Breaker

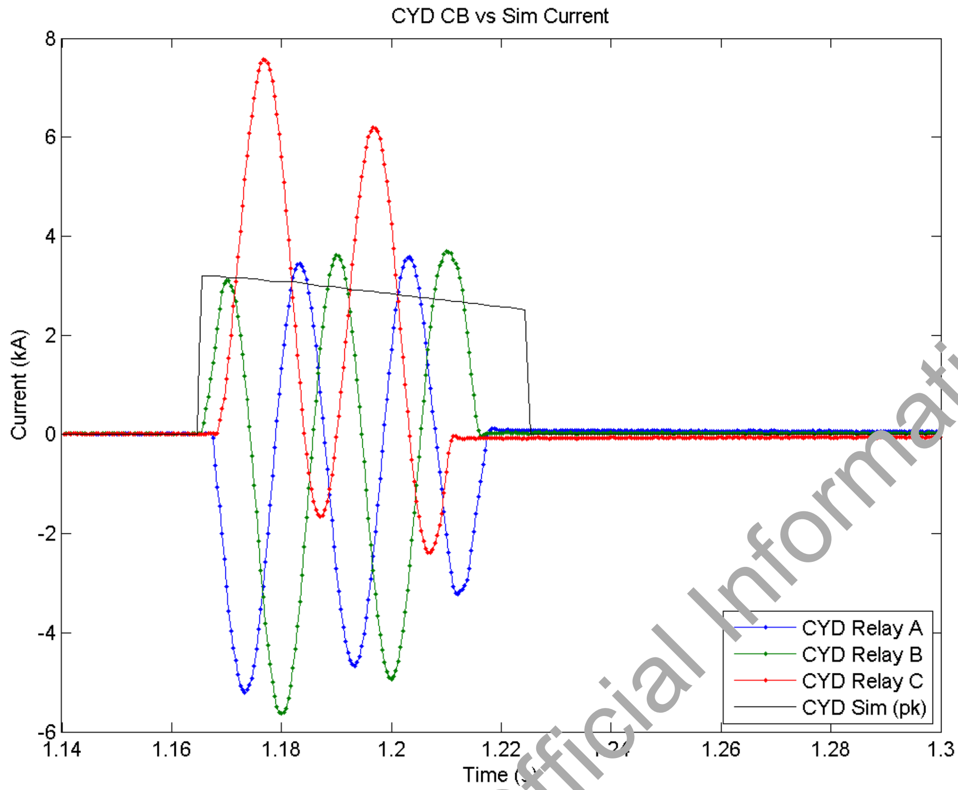
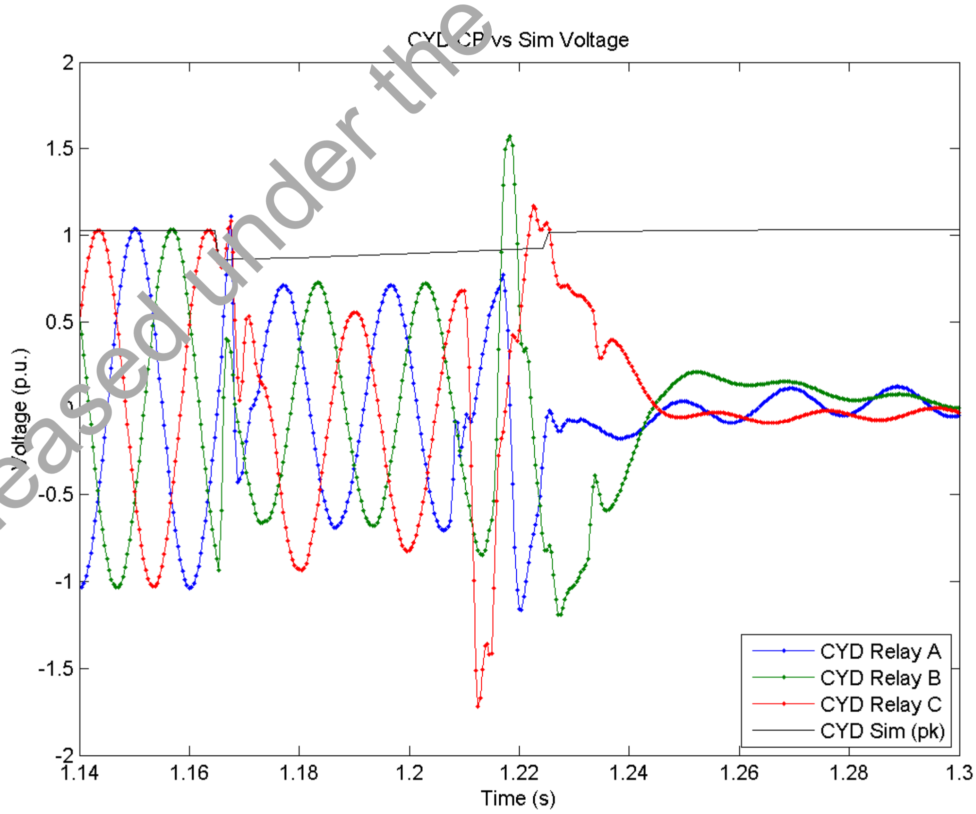


Figure 5B. 1st Attempt to Re-synchronize – Voltage at Clyde End of Line



4. Transient Torques on Generators

The two out-of-phase re-synchronizations resulted in disturbances to the system and raised concerns that damage may have occurred to generators. The torques on the generators are not recorded but they can be estimated by calculation.

Transpower has carried out transient stability simulations on the DigSilent Powerfactory program [9]. The simulations were intended to determine the transient electrical synchronizing torque applied to generators during the 1st and 2nd re-synchronizations. By way of comparison, simulations were also carried out to find the transient torque that would be applied for a 50 ms 3 phase bus fault on the generator's 220 kV point of connection just prior to the system split [10].

Transpower's transient stability simulations are based on positive sequence currents and voltages, and do not account for the DC offset that is observed in the measured synchronizing currents. The DC offset will result in a 50 Hz component in the electrical torque which is not simulated but will be similar to the 50 Hz torque component associated with the DC offset in a 3 phase fault. Accurate simulation of the DC offset will require a fast transient simulation on a program such as EMTP or PSCAD.

Figures 6A – 6I plot the transient electrical torques at a number of generators in the South Island. Table 2 compares the peak torques from the plots.

For both the 1st and 2nd re-synchronizations, the Upper South Island generators are initially braked by the torques whilst the Lower South Island generators are initially accelerated by the torques. This is because the phase of the Upper South Island generators was leading the phase of the Lower South Island generators. If the phase difference had been zero then the frequency difference would have had a more pronounced opposite effect where the Upper South Island generators would have been accelerated and the Lower South Island generators would have braked.

For most generators, the peak electrical torques applied during the re-synchronizations are comparable to the peak electrical torque applied during a 3 phase bus fault. The notable exceptions are for Waitaki, Clyde, and Roxburgh.

At Waitaki, the peak electrical torque of 1.6 pu for the 2nd re-synchronization is significantly higher than for the bus fault. However this is the same as the peak electrical torque at Benmore for a bus fault so is not considered to be unusual.

[9] Transpower Simulations
[10] Note that a 50 ms 3 phase bus fault is significantly less onerous than the Electricity Authority's generator fault ride through requirement of 140 ms for a 3 phase bus fault (The Code, Part 8 – Common Quality, Section 8.25A ' Fault Ride Through').

At Clyde and Roxburgh (the generators closest to the point of re-synchronization at Clyde), the peak electrical torque is negative which would tend to accelerate the machines. However, the absolute magnitude of this negative torque is less than the steady state rated torque.

The engineers carrying out the simulations had expected that the electrical torques associated with the re-synchronizations would be considerably higher than that seen in the simulations. A possible reason for this was the effect of the impedance of the long Clyde-Cromwell-Twizel circuits which acted to limit the synchronizing currents. This was tested by repeating the simulation for the 1st re-synchronization but with the impedance of the Clyde-Cromwell-Twizel circuits reduced to 1% of their actual value. Figures 7A-7I and Table 2 show that the reduced impedance results in significantly higher values of the peak electrical torque.

In general, the results of Transpower's simulations suggest that the transient electrical torques applied to South Island generators during the re-synchronizations were comparable to the transient electrical torques that would be expected for a 3 phase bus fault at the generators' 220 kV points of connection. The results also suggest that the impedance of the long Clyde-Cromwell-Twizel circuits helped to reduce the transient torques, and that out of phase re-synchronization across a short circuit is likely to lead to more severe transient torques.

Table 2. Comparison of Peak Electrical Torques (pu) Applied to Generators in Simulations

Generator	Bus Fault	1st Re-synch	2nd Re-synch	1st Re-synch Short line
Upper South Island				
Aviemore	1.3	1.3	1.1	1.8
Benmore	1.6	1.5	1.4	2.1
Ohau A	1.2	1.3	1.2	1.9
Ohau B	1.2	1.4	1.2	2.1
Ohau C	1.1	1.3	1.2	2.0
Waitaki	1.0	1.2	1.6	1.6
Lower South Island				
Clyde	0.9	-0.3	0.8	-1.7
Manapouri	1.1	0.9	1.2	0.9
Roxburgh	0.7	-0.6	0.6	-2.3

Figure 6A. Transient Torques at Aviemore

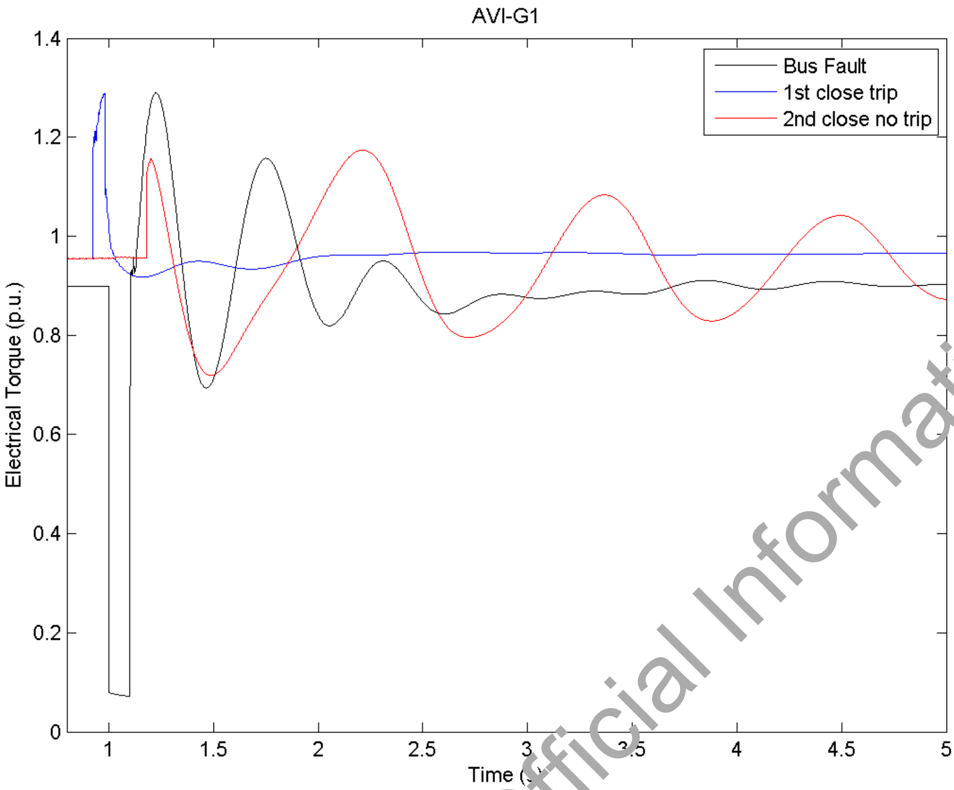


Figure 6B. Transient Torques at Benmore

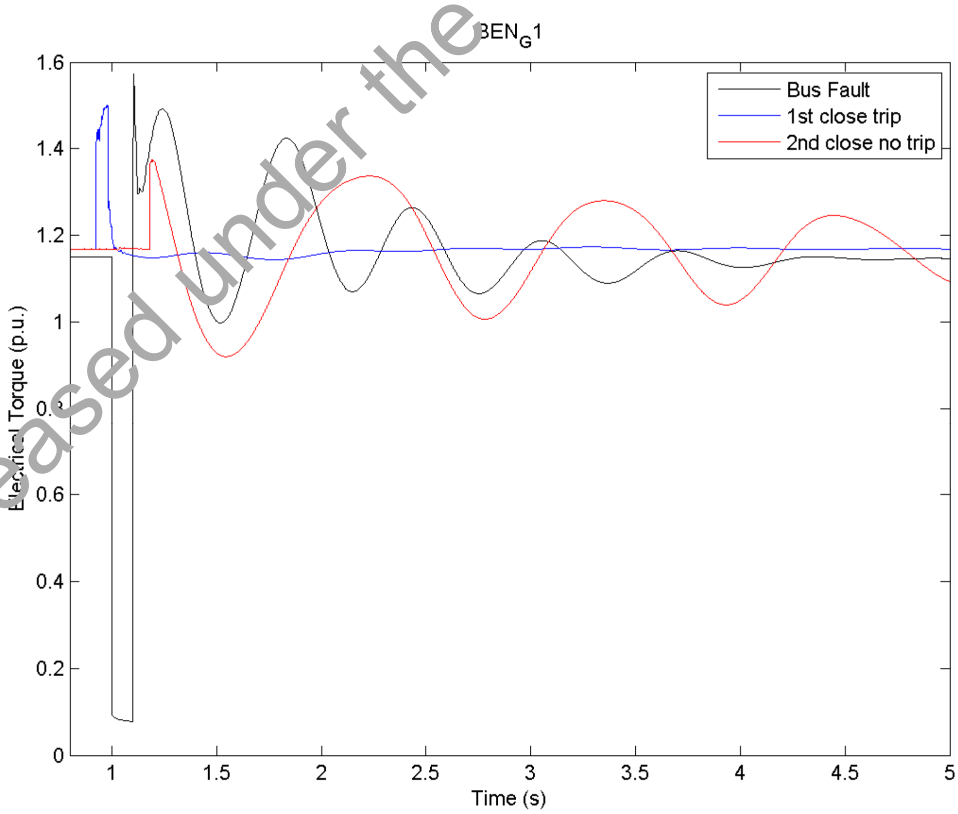


Figure 6C. Transient Torques at Ohau A

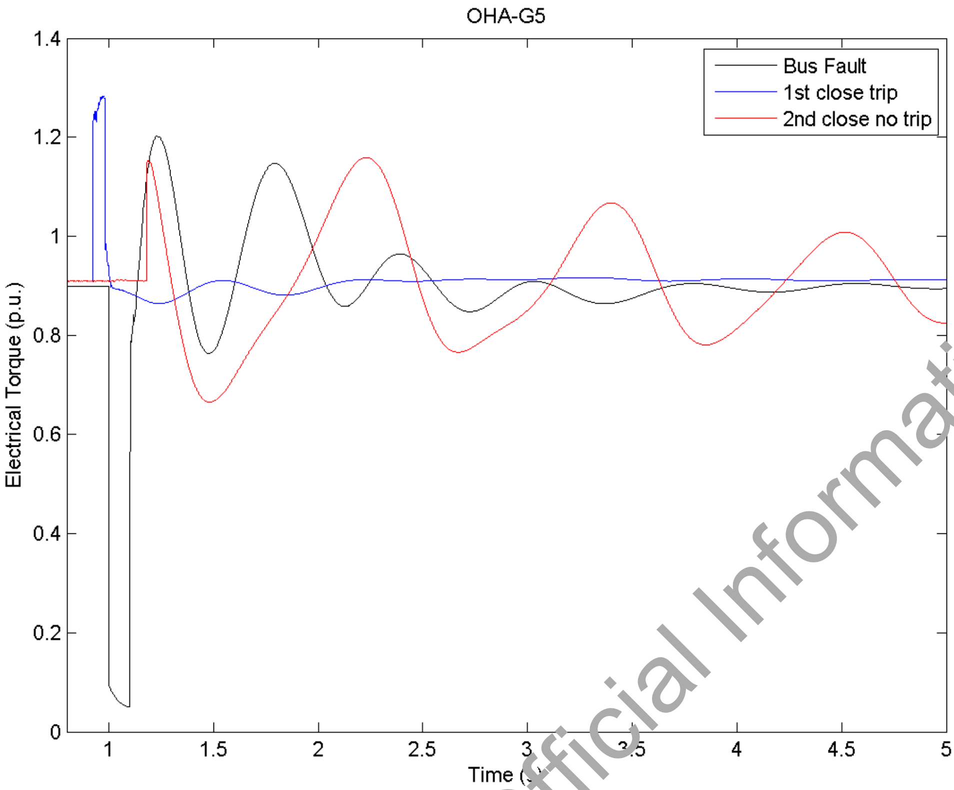


Figure 6D. Transient Torques at Ohau B

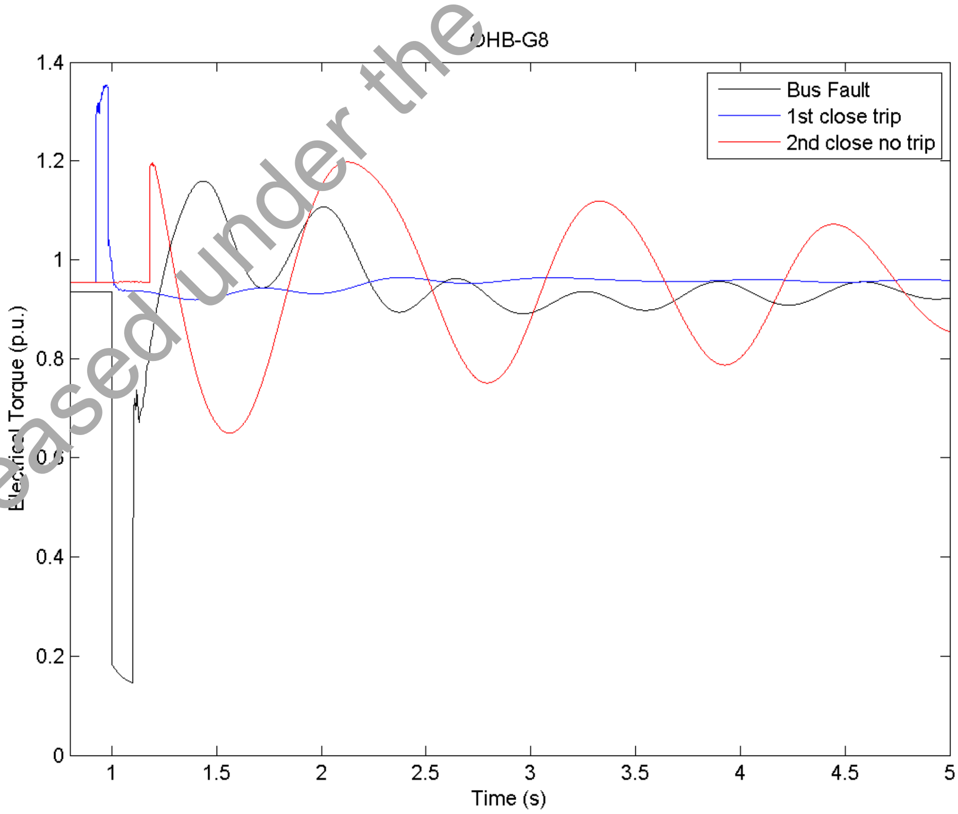


Figure 6E. Transient Torques at Ohau C

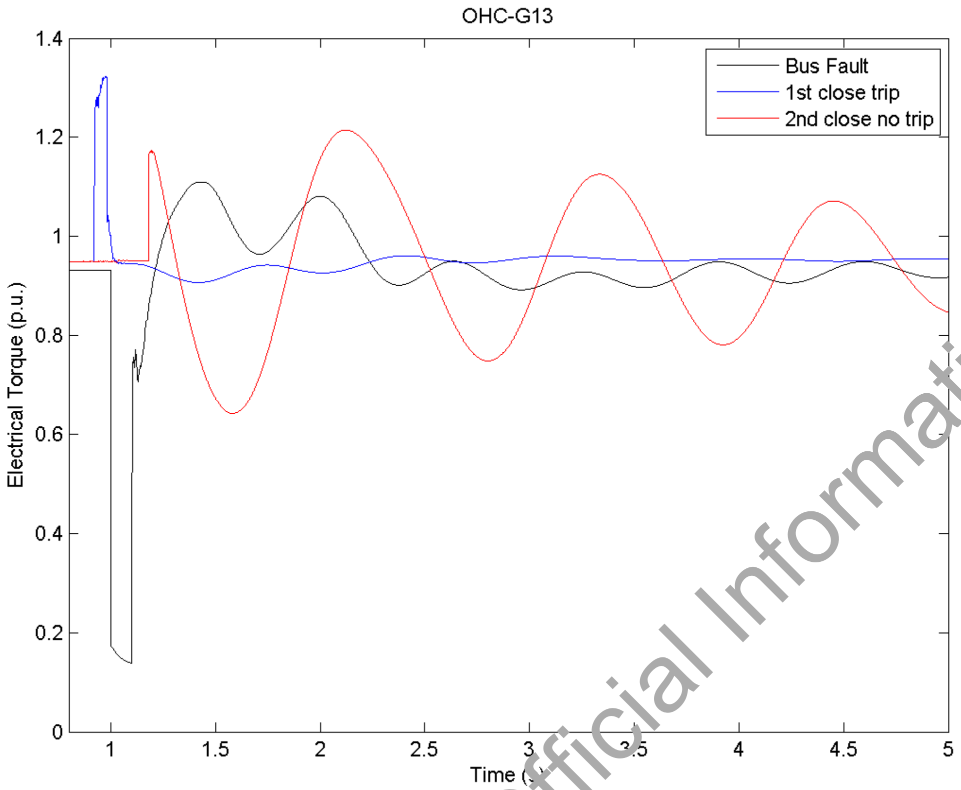


Figure 6F. Transient Torques at Waitaki

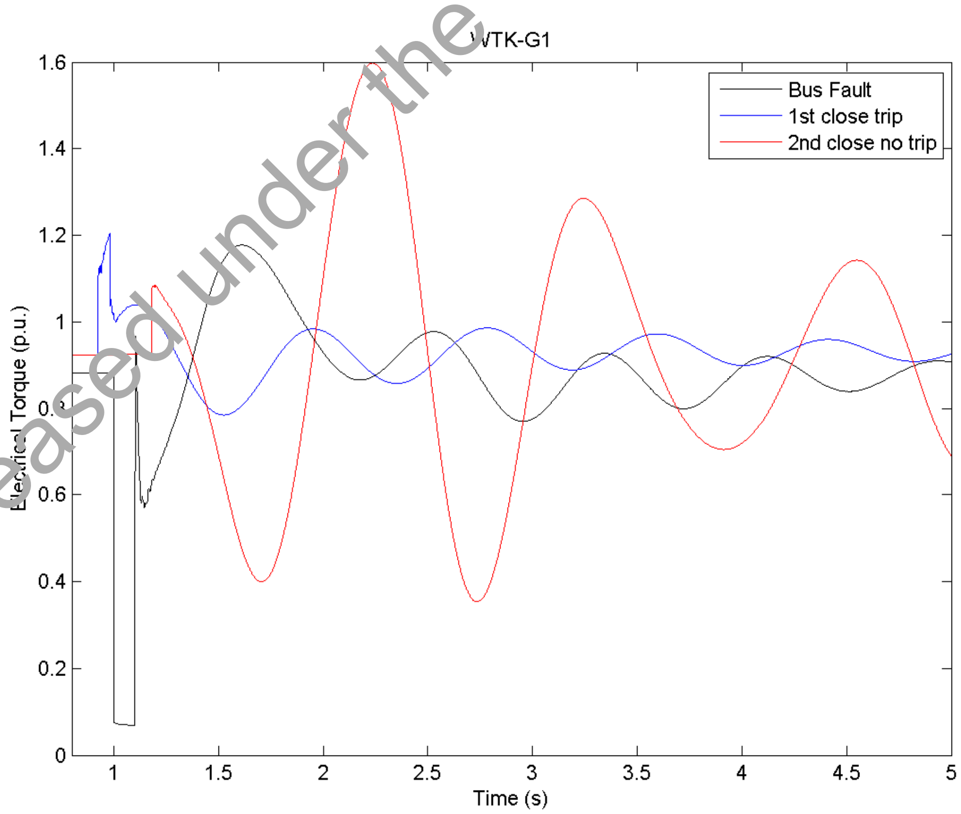


Figure 6G. Transient Torques at Clyde

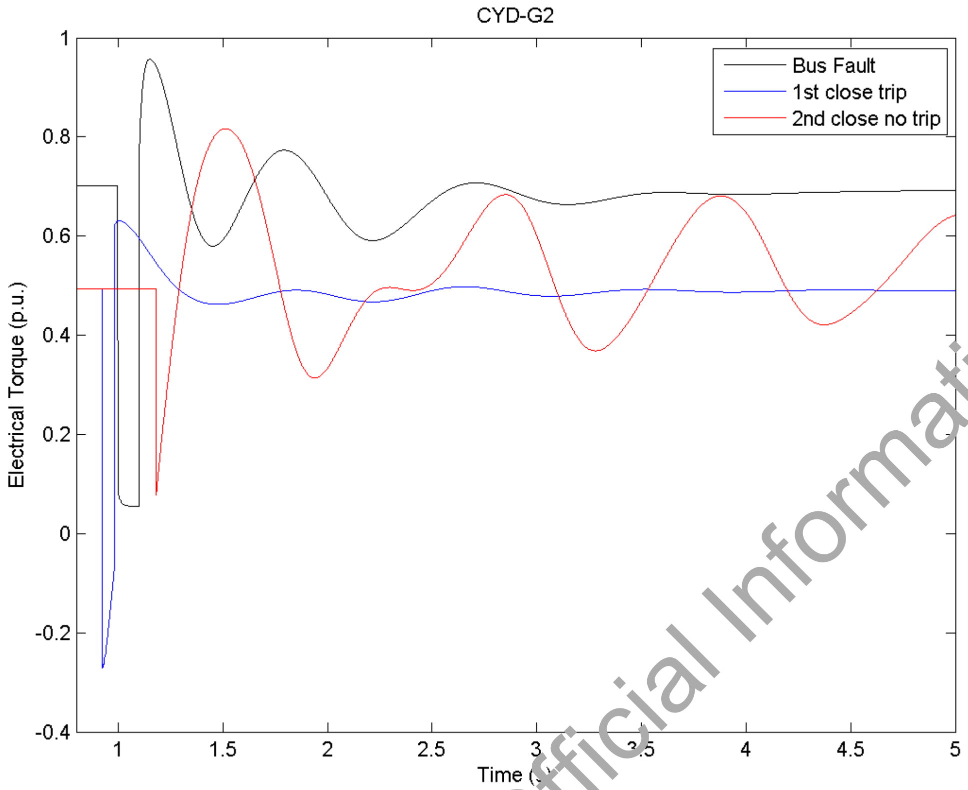


Figure 6H. Transient Torques at Manapouri

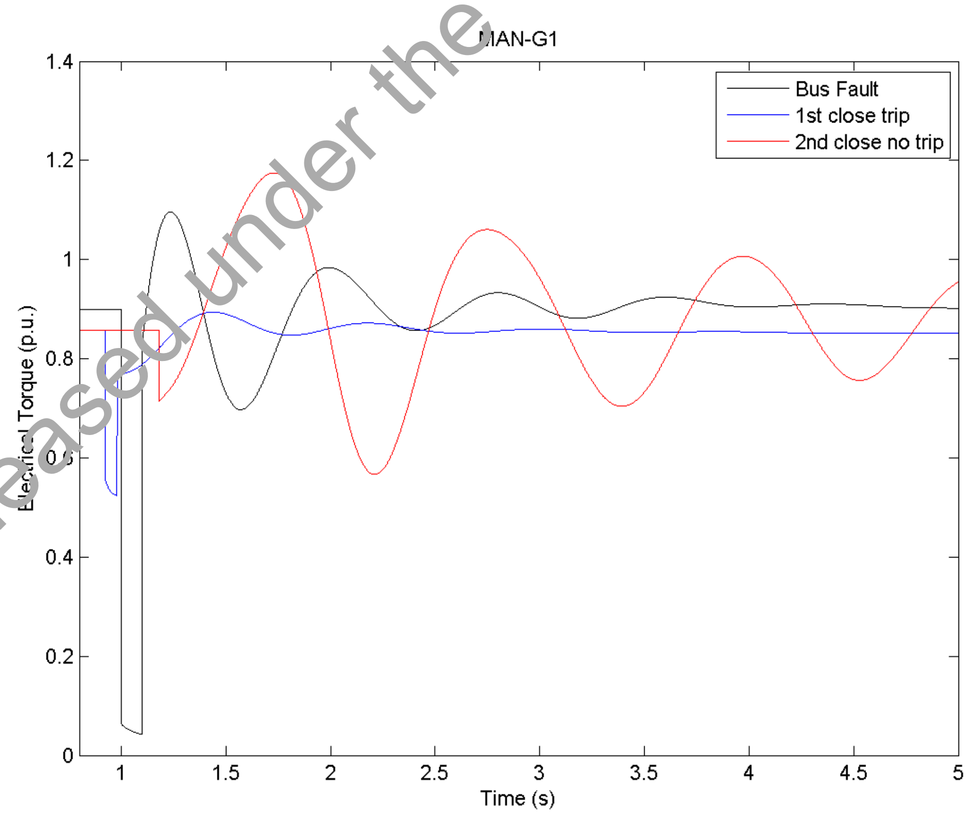


Figure 6l. Transient Torques at Roxburgh

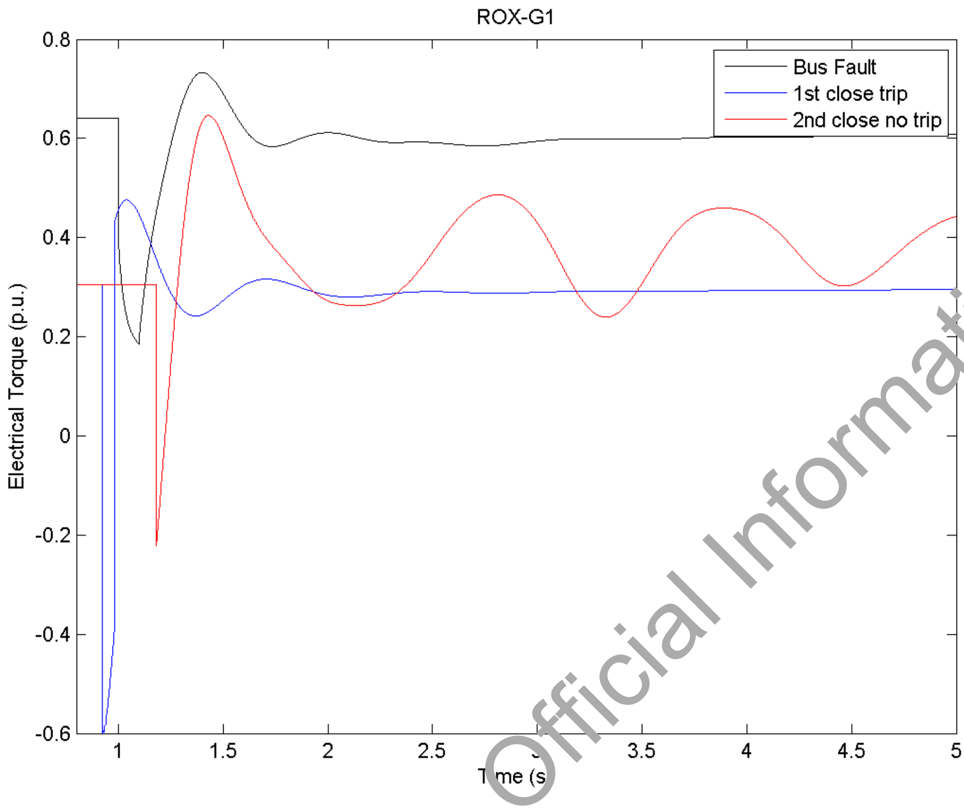


Figure 7A. Effect of Short Line Re-Synchronization at Aviemore

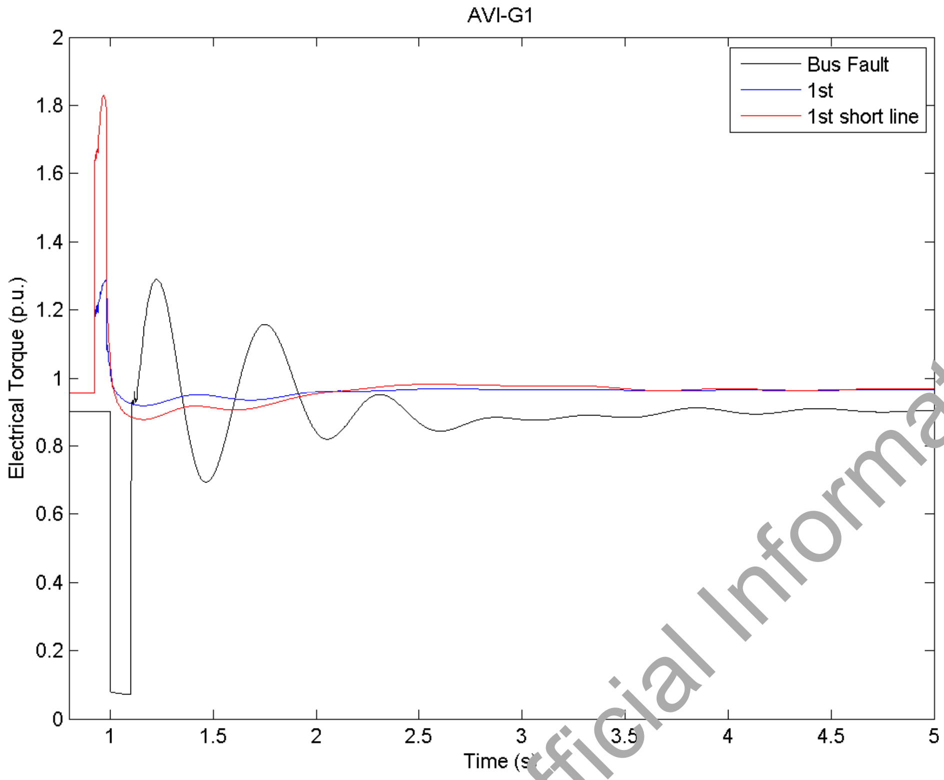


Figure 7B. Effect of Short Line Re-Synchronization at Benmore

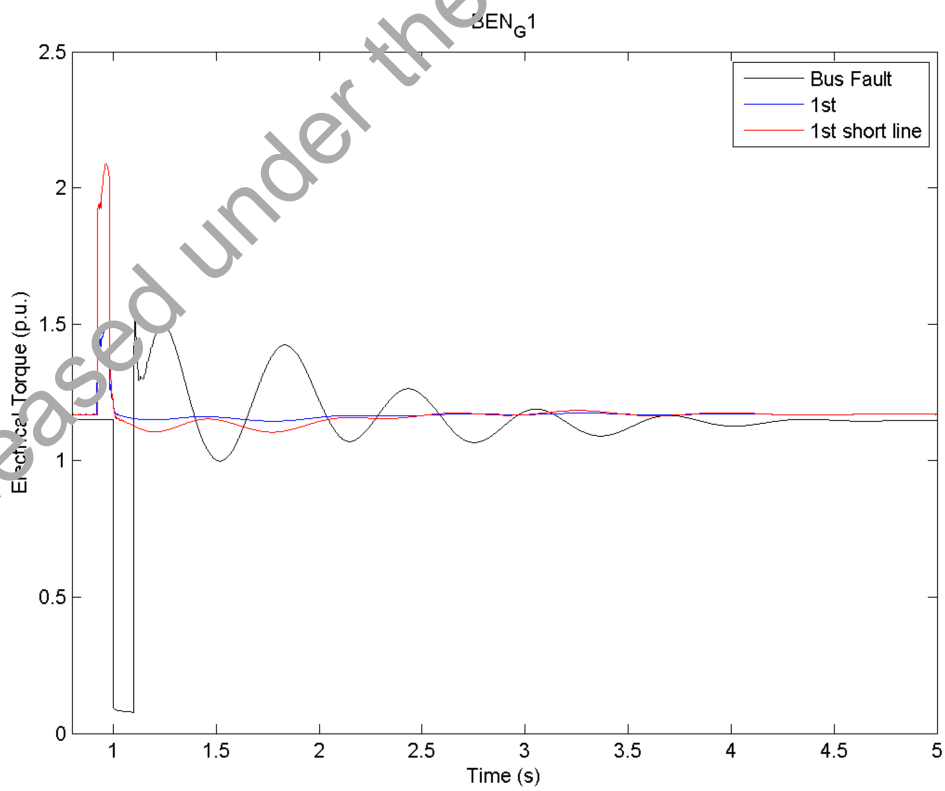


Figure 7C. Effect of Short Line Re-Synchronization at Ohau A

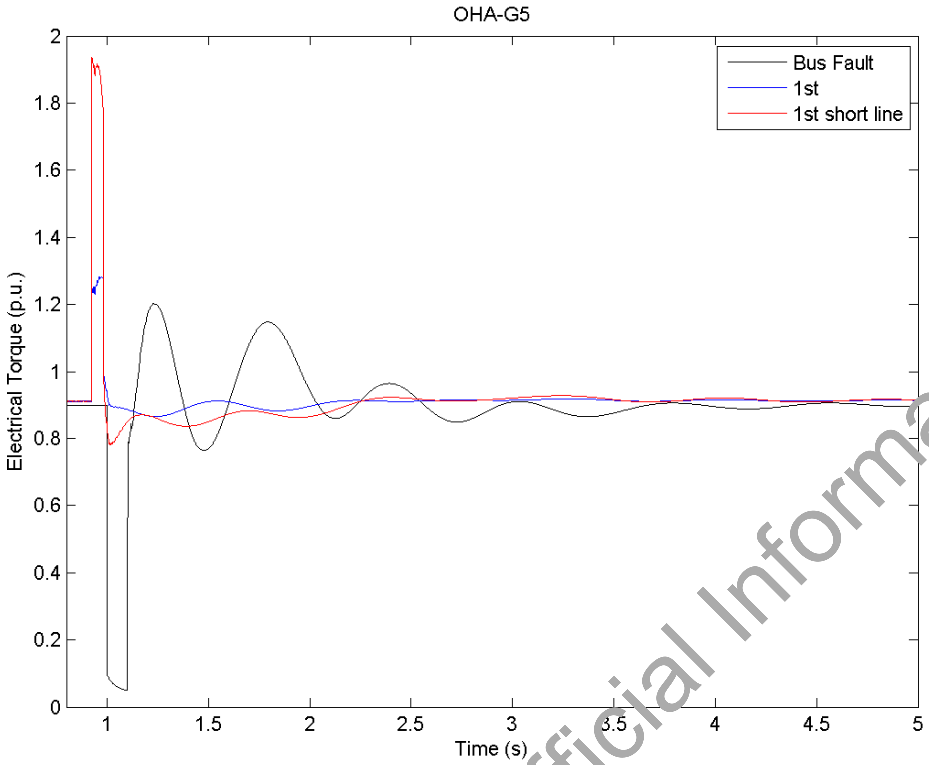


Figure 7D. Effect of Short Line Re-Synchronization at Ohau B

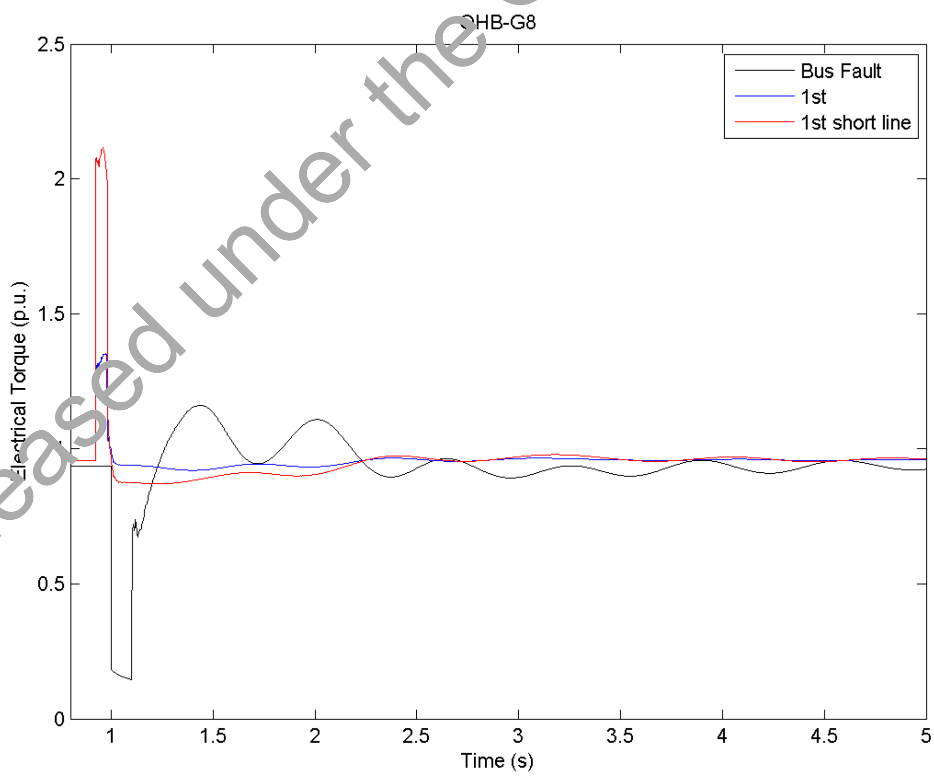


Figure 7E. Effect of Short Line Re-Synchronization at Ohau C

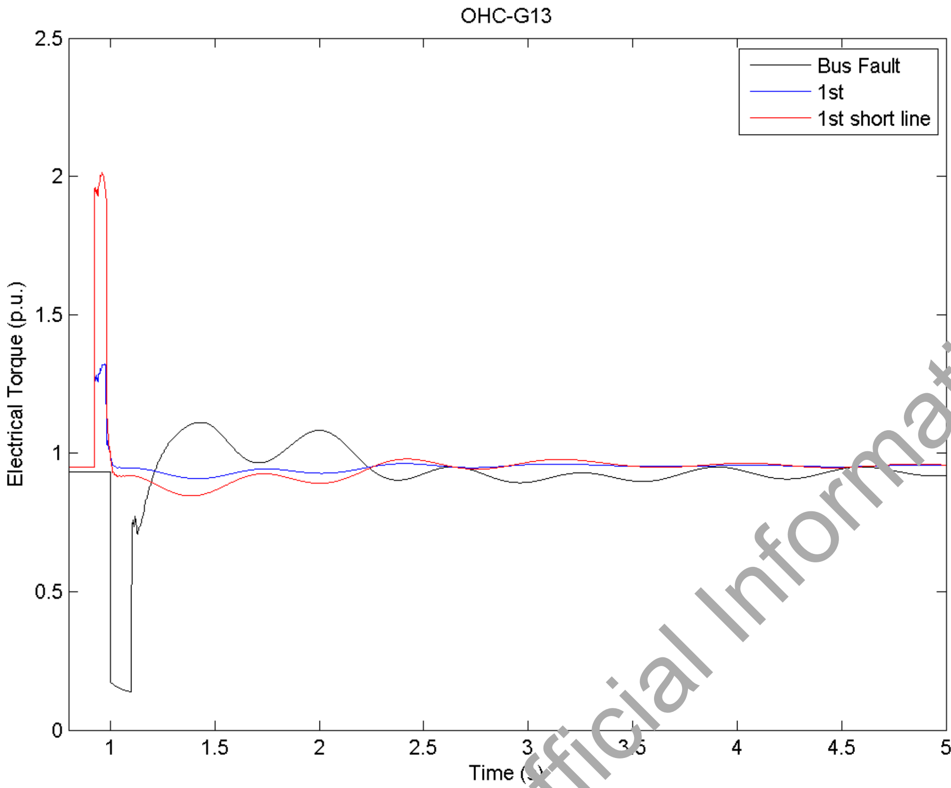


Figure 7F. Effect of Short Line Re-Synchronization at Waitaki

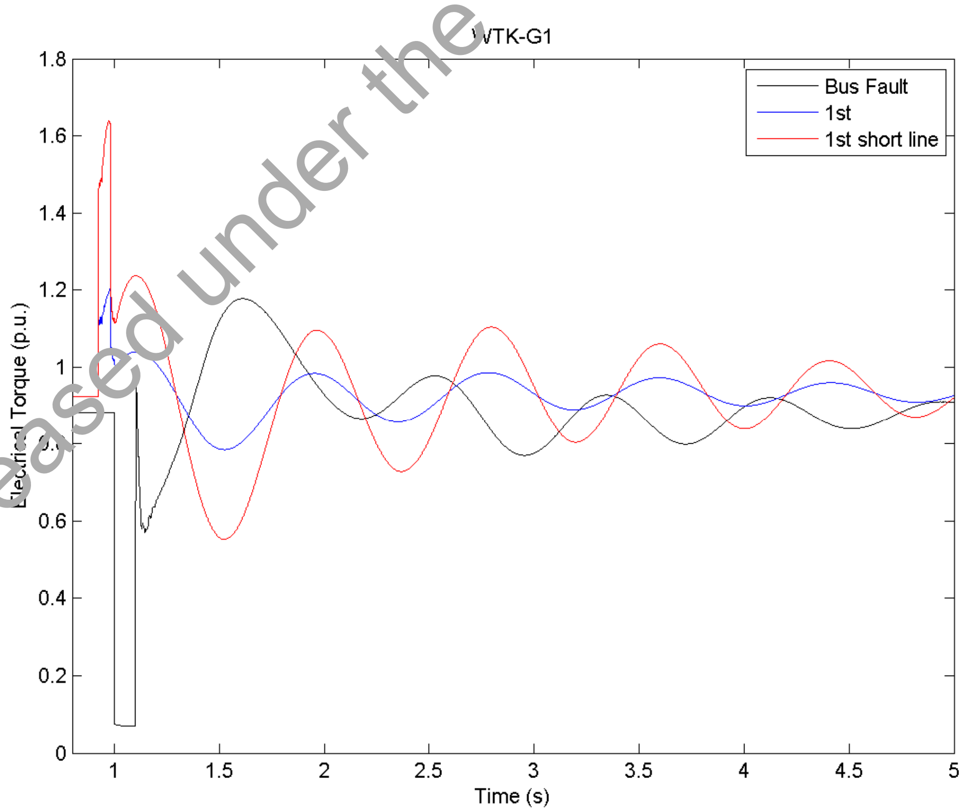


Figure 7G. Effect of Short Line Re-Synchronization at Clyde

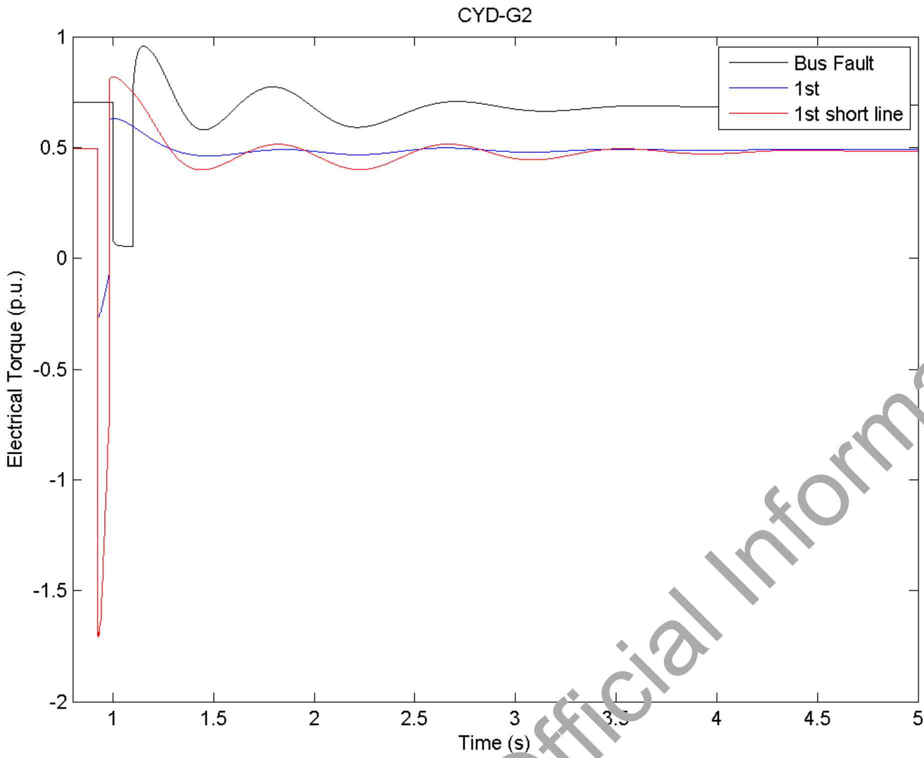


Figure 7H. Effect of Short Line Re-Synchronization at Manapouri

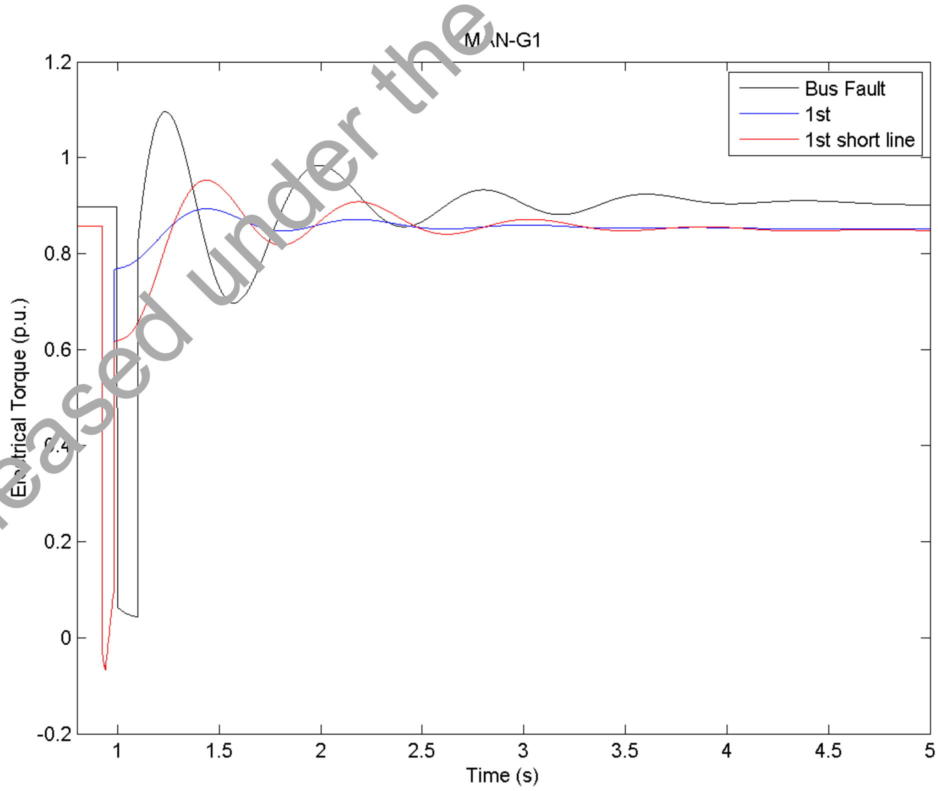
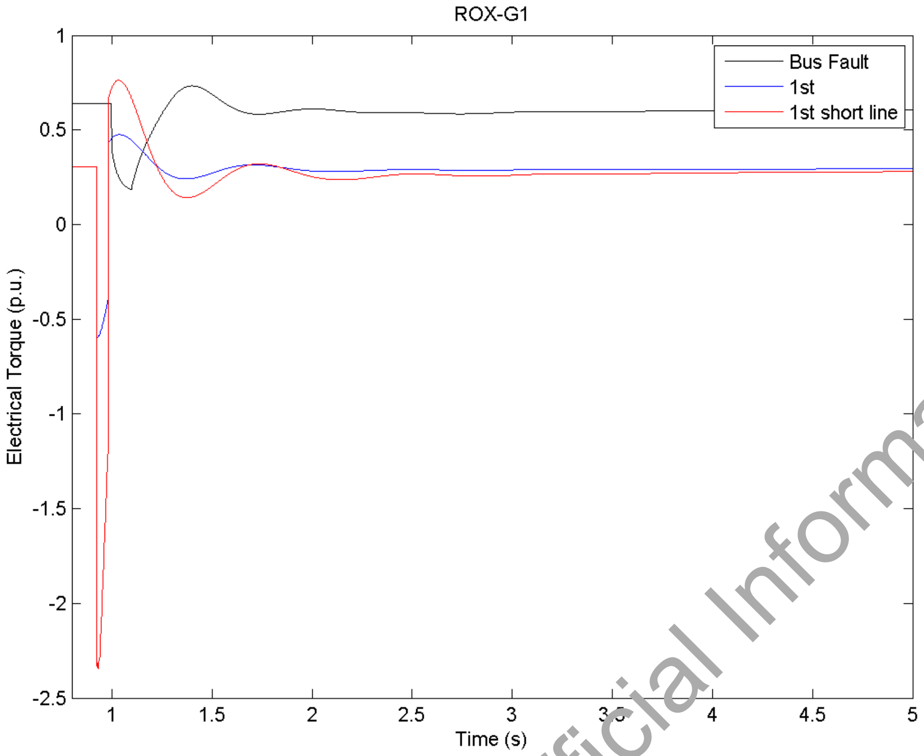


Figure 7H. Effect of Short Line Re-Synchronization at Roxburgh



5. Significant Issues and Possible Solutions

The South Island split on 2 March 2017 highlighted a variety of issues to be addressed. In PSC's opinion, the split was the end consequence of a chain of three independent and unrelated problems :

1) Not adhering to the philosophy of 'Security and Maintainability by Design' for the 220 kV protection at Clyde.

2) Insufficient consideration in the outage planning process around the risks associated with maintenance on 220 kV protection at Clyde during high power transfers from the Lower South Island to Upper South Island.

3) A lack of situational awareness by technicians working on the 220 kV protection at Clyde.

If any one of these problems had not been present, then this particular incident would likely not have occurred.

After the split, the re-synchronization of the South Island revealed issues with NCC and NGOC understanding of policy around returning lines to service as well as their training on the auto-synchronization scheme.

This section of the report discusses the issues in the time order they occurred during the incident, and suggests possible solutions.

5.1. Security and Maintainability by Design

Transpower has a 'Security and Maintainability by Design' philosophy which should guide the designers of Transpower's protection schemes to develop designs that facilitate the testing of protection relays.

The 2015 upgrade to the 220 kV protection at Clyde included the installation of circuit breaker fail inter-trips on the Clyde – Cromwell – Twizel 220 kV circuits. There were two main issues associated with this upgrade with respect to Security and Maintainability by Design :

1) The upgrade design did not allow the output of the Clyde circuit breaker fail timer relay to be easily isolated by a service/test switch.
2) Documentation associated with the upgrade did not clearly describe the signal paths used by the inter-trip.

PSC recommends that Transpower's Protection and Automation Team uses this incident to emphasize the philosophy of Security and Maintainability by Design. Specifically the need for providing practical methods for isolating protection relay outputs, and providing clear documentation of protection signal paths. (We note that Transpower has already published a 'Quality Alert' on this topic [11]).

5.2. Outage Planning Policy for Protection Maintenance

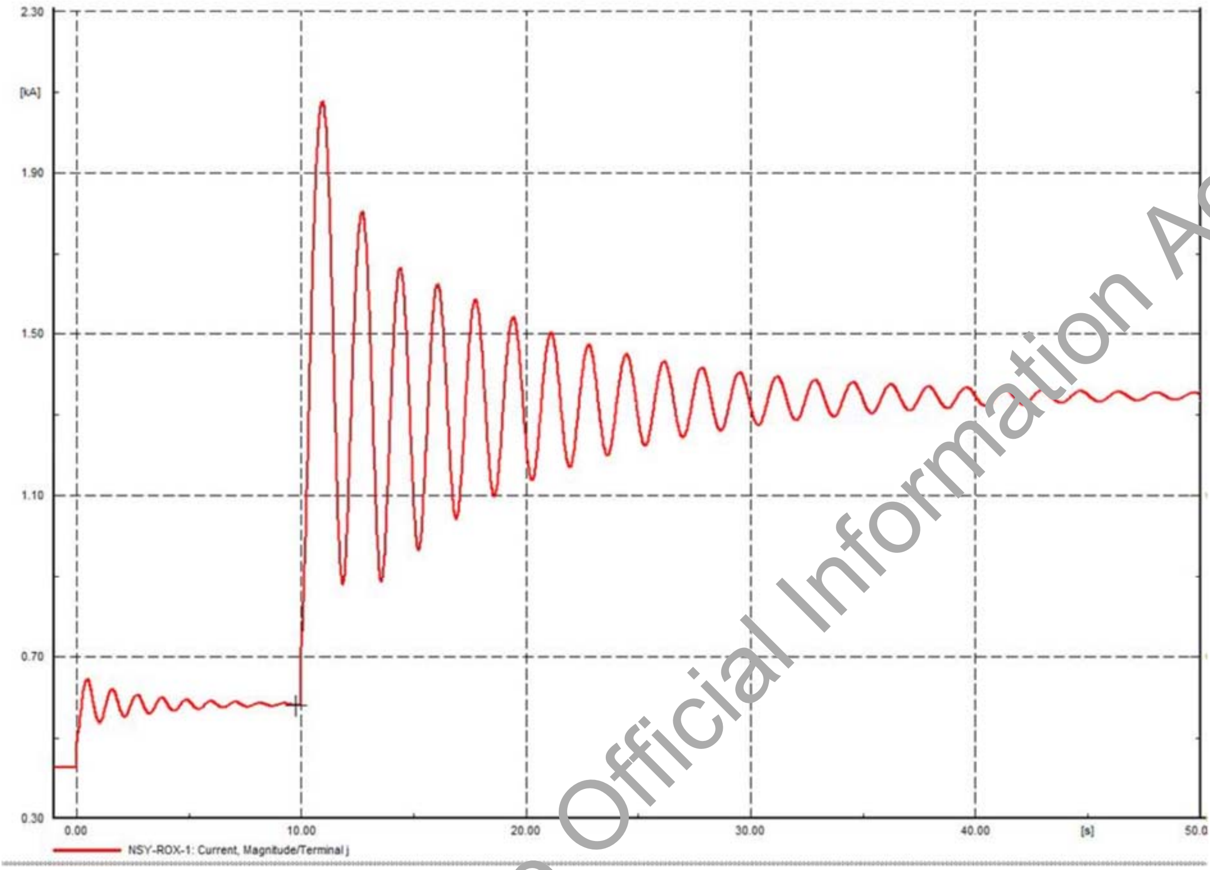
Transpower's outage planning process typically schedules multiple maintenance activities scattered around the network on the same day. Wherever possible, the maintenance activities are scheduled to ensure their independence from each other, such that an unexpected tripping due to one activity does not interact with an outage from another activity to result in unacceptable security or a loss of supply.

When scheduling maintenance and outages on 2 March 2017, the outage planning process scheduled maintenance work on the Clyde 220 kV protection at the same time as an outage on the Livingstone – Naseby 220 kV circuit. The outage planners considered the N-1-1 scenario of an outage on the Livingstone – Naseby circuit plus a tripping of one Clyde – Cromwell – Twizel 220 kV circuit, and determined that the overload on the remaining circuit could be reduced in the 15 minute offload time allowed for system re-dispatch. The planners did not allow for the Clyde protection maintenance tripping both Clyde – Cromwell – Twizel circuits resulting in the N-1-2 scenario that split the South Island network (double contingencies are not normally considered during outage planning).

As part of this investigation, Transpower was asked to simulate the effect of progressively tripping both Clyde – Cromwell – Twizel circuits if the Livingstone – Naseby – Roxburgh circuit was still in service [12]. Figure 8 shows that the first tripping would result in a slight oscillation in the current on the Naseby – Roxburgh section, and the second tripping would result in a much larger current oscillation as the generator rotors in the Upper and Lower South Island swung against each other. The steady state current would reach about 250% of the continuous rating, allowing only 1 minute for generator re-dispatch to reduce the current and avoid excessive sagging and tripping due to a flashover to ground. It is possible that the oscillations would result in protection tripping the circuit, although this has yet to be confirmed.

[11] Transpower Quality Alert
[12] Transpower Simulations with Livingstone-Naseby in service.

Figure 9. Simulated Current Oscillations on Naseby – Roxburgh Circuit (kA)



The simulations suggest that if the Clyde – Cromwell – Twizel circuits had been tripped whilst the Livingstone – Naseby – Roxburgh circuit was still in service then the network split would still have occurred.

PSC recommends that Transpower's outage planning process considers the effect of N-2 contingencies when there is a heightened risk associated with protection maintenance work.

With respect to outage planning on the Clyde-Cromwell-Clyde 220 kV circuits, possible mitigations could include :

- *Carrying out the maintenance at reduced levels of transfer from the Lower to Upper South Island so that a double circuit tripping would not overload and trip the remaining Roxburgh-Naseby-Livingstone 220 kV circuit.*
- *Dispatching extra spinning reserve in the Upper South Island or North island so that AUFLS load is not shed in the event of a double circuit tripping.*
- *Planning for re-synchronization of the Lower and Upper South Island in the event of a double circuit tripping.*

5.3. Situational Awareness for Protection Work

Historically, technicians working in protection relay rooms were in communication with a station operator in the local control room which had a mimic board and audible alarms. If an unexpected tripping occurred, the control room operator would typically ask the technicians if they might be the cause – this would at least give the technicians some pause for thought before carrying on with their work.

More recently, technicians carrying out protection maintenance tend to be much more isolated from external events - they work in a 'bubble' with very little situational awareness of what is happening on the wider grid and no local operator to communicate with. This is exemplified in this particular incident where the technicians inadvertently tripped a circuit and continued on to trip a parallel circuit 46 seconds later without any awareness of the consequences of their actions.

PSC recommends that Transpower considers improving the situational awareness of technicians carrying out protection maintenance. One possibility is to give the technicians access to Near Real Time SCADA on a laptop to let them observe the operation of the local network [13].

5.4. Problems with Aviemore Runback

A few seconds after the South Island network was split, the Aviemore generators ran back by about 159 MW. This runback was caused by an incorrect setting in the Aviemore governor controls which was intended to runback for over-frequency rather than under-frequency.

PSC recommends that Meridian rectify the incorrect settings in the Aviemore generator runback. (We have been advised that Meridian have already rectified this problem).

[13] Near Real Time SCADA allows SCADA displays to be viewed by users who are remote from NCC or NGOC. The displayed data is refreshed much more slowly than the normal SCADA displays, but still provides the user with good information about system performance.

5.5. Training on Policy on Restoring Circuits to Service

Transpower's policy on 'Circuit Tripping Response Management' [14] requires that if a circuit trips and is not automatically reconnected, then manual restoration should only be carried out after assessing safety risks and impacts to the system. If the circuit crosses public spaces then Transpower will normally deploy a line patrol to check those spaces.

If a Grid Emergency has been declared and there is a need to rapidly restore the network, then the circuit can be restored without a line patrol, provided the cause of the tripping is understood and it is clear that it is safe to return the circuit to service. The policy gives a specific example where "*a contractor on site has advised that the work they were carrying out caused the tripping and that they are now clear*".

It appears that the protection technicians at Clyde had yet to inform NGOC of their involvement in the splitting at the time that the NGOC Grid Asset Controller decided to make the circuits available for service. According to the policy, there was insufficient evidence that the circuits could be restored safely and without adversely impacting the system.

Both the NCC Security Coordinator and NGOC Grid Asset Controller should have a good working knowledge of this policy, and it appears that this was forgotten in their haste to re-synchronize the network.

PSC recommends that NCC and NGOC review training on Transpower's policy on 'Circuit Tripping Response Management', particularly with respect to restoring circuits only when the reason for tripping is understood. The training might use this particular incident as an example of errors that can be made when working under pressure.

[14] Transpower Response Management Report

5.6. Training on Auto-Synchronization

The NCC Security Coordinator and NGOC Grid Asset Controller appear to have been confused over the procedure for auto-synchronization and they did not look at the auto-synchronization documentation during the incident. The auto-synchronization display was visible on SCADA at both NCC and NGOC, however neither realized that the auto-synchronization function was not enabled. The NGOC Grid Asset Controller used the auto-synchronization display to close the breaker manually in the mistaken belief that this would start the auto-synchronization process.

When the 1st re-synchronization failed due to the large synchronizing currents causing Zone 1 distance protection to trip the circuit, the tripping alarms appeared on SCADA at both NCC and NGOC. It appears that nobody at NCC or NGOC realized that the tripping of the circuit implied that an out-of-phase re-synchronization had occurred along with a severe disturbance.

The same errors were repeated for the 2nd re-synchronization, however by good fortune the phase and frequency discrepancies between the islands were small enough to successfully re-synchronize the islands, albeit with some disturbance.

Historically, manual synchronization was carried out locally at selected stations using a synchroscope similar to that shown in Figure 9. Synchroscopes were frequently used for connecting generators to the grid, and occasionally for reconnecting islands in the grid. The operator would control generators to adjust voltage and frequency until the voltage magnitude, voltage phase, and frequency were matched, and then close the circuit breaker. As a matter of professional pride, operators would try to make the synchronization as smooth and 'bumpless' as possible. They were very conscious of a bad bump which would result in a visible light flicker and a shudder in the power station.

Figure 9. Synchroscope

Manual synchronization was replaced by auto-synchronization in 2015, although the manual synchronization function is still retained as a backup. The auto-synchronization function is available on SCADA screens at NCC and NGOC, and is intended to be used by NGOC when instructed by NCC.

NCC coordinators and NGOC controllers were trained on the auto-synchronization function when it was initially installed, and the NCC coordinators had one more training round after installation. None of the training sessions were on the simulator. The incident on 2 March 2017 was the first time auto-synchronization had been used in a Grid Emergency.

In contrast, it appears that NCC and NGOC are regularly trained on System Protection Schemes (SPS) which also infrequently operate, similarly to the auto-synchronization scheme. This suggests that the lack of training on the auto-synchronization scheme is an over-sight rather than a systemic training problem.

PSC recommends that more frequent training is provided on auto-synchronization at both NCC and NGOC using the training simulator. The simulator should be able to simulate the time required for the process (up to 5 minutes before timing out), and simulate the impacts of a good and bad synchronization.

PSC also recommends that Transpower ensures training is provided to operators who may have to use manual synchronization with synchroscopes as a backup to the auto-synchronization.

References

Electrix Protection Report	'Clyde Circuit Breaker Fail Intertrip Event', Electrix Reference FICS 20620, 24 March 2017.
HVDC Report	'HVDC Response to the March 2017 AUFLS Event', Transpower New Zealand Ltd.
Transpower Response Management Report	'Circuit Tripping Response Management', Transpower TP.AOI 07.518, Issue 5, October 2016.
Transpower NCC Report	'NCC Review of the South Island AUFLS – Islanding Event 02-March-2017', Transpower New Zealand Ltd, 27 March 2017.
Transpower NGOC Report	'NGOC Investigation Report – South Island Split and Auto Sync Event 02/03/17', 9 March 2017.
Transpower Preliminary Report	'March 2017 South Island AUFLS Event Preliminary Report', Transpower New Zealand Ltd, March 2017.
Transpower Protection Report	'Clyde AUFLS Frequency Loss of Supply & System Split Event on 2 March 2017', Transpower Protection and Automation Group, Version 2, 28 March 2017.
Transpower Quality Alert	'CB Fail Intertrip Isolation During Testing', Maximo REF No. 96913, 11 May 2017.
Transpower Simulations	Simulations carried out by Victor Lo (Transpower Grid Development) and Richard Sherry (Transpower System Operator), May 2017.
Transpower Simulations with Livingstone-Naseby in service	Simulations carried out by Jaleel Mesbah (Transpower) on effect of tripping Clyde-Cromwell-Twizel circuits with Livingstone-Naseby circuit still in service, August 2017.

Appendix 1 Scope of Work

PSC's scope of work from Transpower is to carry out a 'desktop investigation' into the system response to the two disturbances on 2 March 2017. A desktop investigation is typically an initial limited cost investigation based on reviewing reports and some relatively simple hand calculations (it does not include detailed calculations or modelling). The results of the desktop investigation may be used to define the scope of a more detailed investigation at a later stage. This desktop investigation will include :

1) Reviewing the system response in the time period from 11:15 am to 12:32 am. This includes the time period from before the disconnection of the two Clyde-Twizel circuits till completion of load restoration and covers :
    a. The initial disconnection
    b. AUFLS load shedding
    c. Generator Over-frequency tripping
    d. Interruptible load tripping
    e. HVDC response
    f. Restoration of the system, including the re-synchronizing of the system, and subsequent load restoration.
2) Reviewing Transpower's reports on the disturbances.
3) Reviewing Transpower's modelling of the disturbances.
4) Discussions with Transpower's engineers.
5) Determining whether the control and protection systems for generators, lines, AUFLS, HVDC, and interruptible load operated as designed (including a review of whether these disturbances were considered in their design).
6) Review Transpower's reports on the auto-synchronization, particularly with respect to the system response to the out-of-phase re-synchronization.

In addition to the desktop investigation on system response, comments will be made on wider aspects of these incidents, but these are not the prime focus of the work. For example comments may be made on outage coordination for critical parts of the network, situational awareness of technicians working on protection, training of system operators for infrequent tasks such as re-synchronization, and possible implications on policies for Extended Contingency Events.

Appendix 2 Reviewer's Credentials

Ranil de Silva has 34 years of experience in the electrical power industry as an employee of Transpower or its predecessors from 1983 to 1995 and then as a co-founder and Director of Engineering of Power Systems Consultants (PSC) from 1995 to the present. He gained his PhD in Electrical Engineering at the University of Canterbury in 1987.

PSC provides specialist consultancy services to the electricity industry in New Zealand, Australia, Asia, Europe, and North America and employs about 150 staff.

For the purpose of disclosure, PSC has carried out work and/or is currently carrying out work in New Zealand for Transpower, generating companies, distribution lines companies, and the electricity regulator.

Ranil's fields of special competence include :

a) System studies including Load Flow, Short circuit, Stability, Fast Transient Analysis for AC and HVDC systems, and Insulation Coordination
b) Investigation, Specification, Design, Factory Testing, and Commissioning of HVDC Schemes
c) Analysis of Electricity Market Systems
d) Analysis for Electricity Regulators
e) Analysis of Distributed Energy Resources
f) Incident Investigation

Appendix 3 PSC Discussions with Transpower

During the course of this investigation the author, Ranil de Silva, had discussions with the following Transpower employees :

1) Nick Coad (Grid)
    a. Primary client contact for this investigation
2) Scott Avery (System Operator)
    a. Clarify relationship between Transpower Grid and System Operator
3) Richard Sherry (System Operator) and Victor Lo (Transpower Grid Development)
    a. Discuss system response
    b. Modelling to replicate system response
4) Peter Bishop (Transpower Protection & Automation Manager)
    a. Clarify protection actions
5) Alex Joosten (Transpower Grid)
    a. Clarify operation of SPS to split ROX bus and reduce loading on ROX-NSY-LIV circuit
6) Tim Conolly (NCC Manager)
    a. Clarify actions of NCC and NGOC
7) Steve Reeve and Dave Webb (NGOC Managers)
    a. Clarify actions of NCC and NGOC

APPENDIX D: FIELD ISSUES REPORT - BEC CONSULTING

South Island Automatic Under Frequency Load Shedding and Islanding Event

2 March 2017

Field Issues Investigation Report

Version Control

Version	Author	Description	Date
1.0 draft	Barry Hayden	Issue for Client review.	10 November 2017
1.1 draft	Barry Hayden	Readability improvements, R 4 added. Issued for wider review.	23 November 2017
2.0	Barry Hayden	Final	20 April 2018

Investigation Team

Investigation Leader:	Barry Hayden (BEC Consulting)
Investigation Team:	
Contributors:	Electrix Ltd staff, Transpower subject matter experts
Peer Reviewers:	
Lead Author:	Barry Hayden

Investigation Methodology

BEC Consulting was engaged to undertake an independent review of the activities related to the field components of this investigation. The consultant is a self-employed industry practitioner with experience in relevant areas of industry activity.

The investigation is not based on empirical findings or analysis. It is based on the observations and experience of an industry practitioner.

The investigation technique included:

1. Interviewing service provider staff involved in the incident.
2. Discussion with Transpower Staff with subject matter expertise.
3. Reviewing relevant regulations, industry rules, standards, and work control documentation.
4. Analysing results.
5. Comparing with industry best practice techniques.
6. Compiling an investigation report.

This report contains information sufficient to allow the expected audience to understand the relevant events. Additional information used in preparing this report is held on file by Transpower.

Reliance

This report has been prepared by the author for the use of **Transpower NZ Ltd**. Permission should be gained from **Transpower NZ Ltd** before its use or reproduction.

In preparing this report the author has relied on information available in the Transpower and public domain and from interviews.

Professional judgement has been used in assessing the information provided. No representation is made as to the accuracy or completeness of this information.

INCIDENT SUMMARY

What happened?

On 2 March 2017 at 11:20:45, during planned eight yearly maintenance on the Clyde 220kV busbar and circuit breaker fail protection schemes, an intertrip signal was inadvertently sent to Twizel commanding the circuit breakers at the Twizel end of the Clyde–Cromwell-Twizel-2 220kV circuit to open. At 11:21:32, 46 seconds later, the sequence was repeated for the Clyde-Cromwell-Twizel-1 220 kV circuit.

At the time of the tripping, Power Technicians were carrying out functional testing of the circuit breaker fail timers for CB 522 and CB 542 (respectively). The Power Technicians stopped work after noticing the Clyde generators reject load. They discontinued their work, without any awareness of the cause of the system disturbance, and offered help to the operator. They were advised by a Transpower protection engineer at 13:00 (approx.) of what had caused the trippings.

At the time the Livingston-Naseby-1 220kV circuit was out of service for hardware replacement work. This scenario lead to the creation of two electrical islands within the South Island power system. One including Waitaki Valley and the upper South Island and the other including Clutha Valley and the lower South Island.

This rare event resulted in the loss of load due to the operation of under frequency protection in the upper South Island, and the disconnection of interruptible load in the North Island which was triggered to manage a reduction in transfer via the HVDC link. The disconnection of this load combined with three generators tripping on over frequency and collective generator governor response in the lower South Island has been sufficient for the two islands to survive the disturbance.

The work on the bus zone and circuit breaker fail schemes was abandoned and the assets made available for service.

No request was made for any manual synchronising support. The Technicians left the site with the maintenance task incomplete. It is yet to be scheduled for completion.

The two islands were reconnected when a remote operator initiated the closing of the circuit breaker(s) at Clyde at 11:44:06.

Key findings of the investigation

The event was caused by a failure to identify the recently installed intertripping equipment and therefore its effect on the work being undertaken. The failure to identify this equipment meant it was not adequately isolated from being able to send command intertrip signal(s) which opened the circuit breakers creating the two islands.

The recently added bus zone CB fail intertrip scheme was complex with drawings of a low quality. The design of isolation points was unintuitive and impractical to achieve the isolation required to allow maintenance to be carried out.

Contributory factors

1. The design for the bus zone CB fail intertrip modification that was added at the same time as automatic synchronising capability did not allow for the isolation capability needed to carry out maintenance safely. The ability of the Technician to understand the design and work on it safely was made difficult and unintuitive.

2. The Technician made reasonable efforts to research the design and prepare an appropriate isolation plan (operating sequence). There was information presented which may have led to the discovery of the modified design had it created sufficient concern in the Technicians mind. He felt he had researched the design sufficiently and completed the Work Method Statement (WMS). The WMS had uncertain document control and it was unclear whether a peer review had been carried out.

3. Information provided to the Technician was of a low quality. The lack of a CB fail initiation path on the R & I diagram, the errors, age and quality of the circuit diagrams and the lack of any project handover/operator notes made it more difficult for the Technician to carry out the work safely.

4. The lack of any indication of an event occurrence in the Clyde relay room meant that the chance to avoid tripping the second circuit was lost.

5. Lack of preparedness for manual synchronising at Clyde meant this option was not available to the operator to consider as a restoration option.

6. No consideration of the impact of coincident outages of NAS-LIV-1 and CLD bus zone CB Fail meant the opportunity to consider whether the risk was acceptable was lost.

Learnings

1. Protection designs in this era have insufficient standardisation of human interface requirements, particularly design and use of isolation devices. Brown field's sites are worse. Designers do not understand the Technician's needs.

2. There is no standard approach to providing situational awareness for Technicians. They have been told not to use/trust some systems. This has resulted in less interest by them in system conditions. They often do not know if their testing has caused any adverse system consequences.

3. There is confusion about the provision of substation information (operator notes). Different stakeholders have different requirements. Designers do not expect to provide what Technicians need.

4. The outage planning process does not take sufficient account of the risk that work on critical protection may pose.

Key actions underway or already completed

1. Fitting of warning labels to Clyde bus zone CB fail intertrip timers.

2. A Quality Alert has been sent to all Protection Technicians to outline the event so they look for similarities in future testing of other schemes.

3. Improvement in the quality of information displayed in R & I diagrams (TP.DP 01.31 updated June 2016).

4. Work has begun on identifying similar "unintuitive" designs in the S1 region.

Recommendations

1. Survey the population of protection designs that have unintuitive isolation designs and a high system consequence. Consider fitting warning labels immediately as an interim measure. Consider how to manage the risk of working on these designs and if necessary undertake a business case analysis to consider retrofitting an improved design.

2. Service provider for Clyde substation to improve WMS document control to clarify version control and approval ready for use.

3. Develop a standard to guide designers on human interface requirements, with a strong emphasis on the design of isolation points and devices. Establish and maintain a Protection national best practice group. This group should have representation from designers, Power Technicians and Asset Managers. Its brief would be to provide feedback to the content of the standard and provide ongoing support to design and asset management decisions.

4. Review the expectations for the provision of information by designers to Service Providers (and others) as required by TP.SS 01.13, Substation Information folder, project notes and asset photographs. Consider strengthening mechanisms to ensure compliance by all parties.

5. Require Protection Technicians to document in their WMS how they will positively affirm that no unacceptable system outcomes have occurred as a result of their actions at each appropriate stage of their testing process.

6. Ensure the risk of work on bus zone CB fail and other wide area tripping schemes, which have a high power system consequence if an error is made during the the work, is reviewed by a protection engineer in the outage planning process.

7. Clarify with service providers where manual synchronising operating services are required. Ensure service is available as specified.

CONTENTS

<u>Appendices</u>

1. Introduction

The 220kV bus configuration at Clyde consists of three separate gas insulated switchgear (GIS) busbars A, B, and C. The bus arrangement includes three 220kV bus couplers, four 220kV circuits, four generators and two transformers. It is a significant station and requires that a high degree of care is taken by anybody working on or near in service equipment.

The three busbars are each protected separately so that a fault on one will allow it to be disconnected and the healthy busbars remain in service. The circuit breaker fail (CBF) scheme is provided to trip the appropriate equipment in the event that a circuit breaker fails to operate when commanded. The CBF is largely separate but uses the bus bar tripping equipment to effect the correct circuit breakers to trip.

The busbar protection equipment is original to the station (circa late 1980's). The 220kV circuit(s) and CBF protection have been upgraded and modified since the station was built.

Notably for this incident, a project was implemented in 2014 to provide the ability at Clyde (and elsewhere) to automatically synchronise two islands upon command. To achieve this, the project upgraded the protection relays on CLD-CLM-TWZ-1 & 2 circuits in order to give the functionality required to enact automatic synchronising. Transpower designers took the opportunity to add additional functionality. Relevant to this incident was the intention to add a bus protection CBF intertrip. This has the benefit of ensuring reduced fault clearance times in the event of a failed CB occurring when commanded to trip by the busbar protection. This is relevant to discussions later in the report.

2. Summary of the Event

The two Service Provider Technicians began work on site at Clyde at 07:00:00 on 2 March 2017. They proceeded to gain operational control of the bus zone and CB fail schemes from the National Grid Operating Centre (NGOC), applied the isolations required by their operating sequence, and began work carrying out the required maintenance tests and checks.

They proceeded to measure the operating values of the AC differential and supervision relays, perform AC and DC insulation tests, carry out bus zone function tests, and were in the process of checking the calibration of the CB fail timers. This involves measuring and adjusting the operating time of the 13 CB fail time delay relays.

Having tested six of these relays, the next relay was that of CB 522 (CLD-CML-TWZ-2). They completed testing of this relay at 11:20:45 with no awareness of any tripping or change in system conditions and continued to CB 542(CLY-CML-TWZ-1) CB fail timer relay. Upon operating this, at 11:21:32 they were alerted to a system disturbance by a rapid load rejection of an adjacent Clyde generator. Upon hearing this they enquired to the Contact Energy operator what had happened. At this early stage the operator had no knowledge of the cause. The Technicians ceased work.

The operation of CB 522 CB fail timer relay had sent an intertrip signal to the remote end circuit breakers at Twizel which opened. At this point the upper and lower South Island remained connected by the single 220kV Clyde-Cromwell-Twizel Circuit 1, as the Livingstone Naseby 220kV circuit was out of service for hardware replacement work. The subsequent operation 46 seconds later of the CB 542 CB fail timer sent an intertrip signal to the remote end circuit breakers at Twizel which opened and disconnected this remaining circuit. The bus zone CB fail intertrip had not been adequately isolated for these circuits allowing intertrip signals to appear at Twizel and operate the in service circuit breakers. At this point the upper and lower South Island became disconnected. The lower South Island had an excess of generation causing its frequency to rise. The upper South Island had a deficit of generation causing its frequency to fall.

The Technicians had no information to alert them to what had just happened. They deduced a system event had occurred from the Clyde generator(s) load change. They discontinued work on the bus zone and CB fail equipment, subsequently returning it to service with the job incomplete. They were advised by telephone from NGOC of the trippings and by a protection engineer of the cause. Later in the day, after confirming they were not needed they left the site.

Protection engineers confirmed the cause of the trippings and that there was no fault on the Clyde-Cromwell-Twizel Circuits 1 and 2. CB 542, Clyde-Cromwell-Twizel-1, was closed at 11:42:52 reconnecting the two islands.

3. Background

Transpower's protection maintenance philosophy requires that a "piecewise overlapping" (Busbar protection familiarisation notes Transpower website) approach is taken to carry out maintenance testing. This is to ensure that secondary assets are tested when the associated primary asset is available to be out of service, but where circuitry and equipment is also associated with other primary assets, the testing is performed up to a convenient point in the design. At a later date when the appropriate primary asset is out of service, the testing will be completed from this same convenient point through to the end of chain required by the design (this will likely be the tripping of circuit breakers, sending of signals to remote stations, or operating some device). The testing is said to be done in a piece wise manner which collectively will lead to protection schemes receiving the level of function testing(known as end to end) required by Transpower.

A busbar and CB fail protection scheme is an example of where all primary assets will not be available to be out of service at the same time and the piece meal testing philosophy will be used to achieve the required maintenance.

The requirement for this testing regime means that the correct and adequate isolation of the secondary circuitry is critically important. Failure to effect correct isolations can lead to trip signals being applied to in service equipment.

From commissioning of the busbar protection in the late 1980's it had been maintained satisfactorily by Transpower service providers using the rules and practises employed at the time. The original design would be considered a standard high impedance bus zone scheme with Power Technicians able to understand its design and functionality from the drawings provided. Thus allowing them to work safely on the scheme. This original design had no provision for a circuit breaker failing, when called upon to trip. This fault scenario would be cleared by the remote line end seeing the fault as Zone 2 and tripping with a delay of ~1 second.

With the project to install automatic synchronising at Clyde, Transpower needed to install new line protection relays with increased functionality. These relays can be commanded to provide the auto sync function when switched into the correct mode. The increased functionality of these new relays allowed Transpower to add a bus zone CB fail intertrip feature to the protection scheme. This would typically improve the fault clearance time for the fault scenario above from 1 second to 0.3 seconds. This action is desirable as it will reduce the chance of system voltage collapse and reduce the damaging forces the GIS switchgear may be subjected to during a fault.

The addition of bus zone CB fail schemes to Transpower designs began about 2008 with green fields projects. Early designs did not have the bus zone CB fail initiate path shown on the R & I diagram. This feature was rectified soon after this design began to propagate (at least by 2011. TP.DP 01.31 Relay and Instrument diagrams was updated June 2016). Although the work at Clyde was done in 2014, it still used the superseded practise of not showing the bus zone CB fail initiate path on the R & I diagram.

4. Preparatory Work

Electrix NZ Ltd are contracted to provide maintenance services for Transpower's equipment at Clyde power station. This includes the preventative maintenance task on the Clyde bus zone (BZ) and CB fail (CBF) schemes.

The requirement for the outage(s) were entered in the annual long range plan on 1 May 2015 and the outage request was submitted on 29 July 2016. The outage for the Livingstone Naseby was rescheduled on 9 December 2016 to occur on 2 and 3 March 2017.

The job was assigned to Technician 1 who investigated and found that no adequate job control documentation existed so began the task of assembling what was needed. The Transpower Service Delivery Manager understood the criticality of this work so agreed to fund the WMS preparation. Technician 1 become fully committed to another project so the job was reassigned to Technician 2. Technician 2 progressed the documentation, concentrating on the operating order, which determines the actions needed to make the equipment safe to work on. He then left a few days later for annual leave. Technician 3 was assigned to complete the job control documentation which he subsequently did.

5. Bus Zone CB fail Intertrip Design

Transpower took the opportunity to add the bus zone CB fail intertrip feature during the automatic synchronising project (2014). It has been a feature that Transpower had not had in the past but with increasing relay functionality has been seen as beneficial. It has been added to green fields designs since 2008 and existing sites when upgrades are initiated for other reasons. Clyde has been one of the early existing sites to have this feature added.

In past designs the failure of a CB to operate when commanded to trip for a bus zone fault would have relied upon the remote end protection seeing and clearing the fault with a time delay of typically 1 second. Adding the bus zone CB fail intertrip feature allows this fault to be cleared in approximately 300 milliseconds.

The designer has added the feature using the ability of the line relays at each end to communicate with each other using mirror bits over a digital communications medium. To interface from the existing CB fail equipment to the line relay the designer has added an external relay to the CB fail timer(s) output in order to provide the required additional contacts. This has created the situation where the existing outputs of the CB fail timer are isolated within the original design but the new outputs for the intertrip are not.

It is not clear what method of isolation the designer would have intended for the purpose of carrying out the required maintenance. Two scenarios exist:

1. The CB fail intertrip(s) be isolated by selecting the associated line protection to test. This would mean to perform the bus zone CB fail maintenance both CLD-CML-TWZ1 & 2 circuit protections would need to be out of service. This is not a tenable situation and service providers could not chose this option, work would not proceed.

2. The intertrip receive at Twizel can be isolated via SCADA. Further investigation by the Technicians may have caused them to discover this feature. This has not been considered a standard method of isolating equipment to make it safe to work on.

The addition of this feature to the bus zone/CB fail protection scheme in 2014 has added complexity to the design which makes it difficult to isolate the equipment to safely carry out work on the scheme. It is likely the designer has not had a good awareness of the tasks needing to be performed by the Technician to carry out maintenance.

6. Provision of Information

The common sources of information that a Technician would use to do his work include:

1. Transpower's R & I diagrams. These provide an overview of the stations single line layout and a starting point to determine how the protection system works. It would be used to determine what needs investigating further when planning work (typically 3-5 A3 sheets).

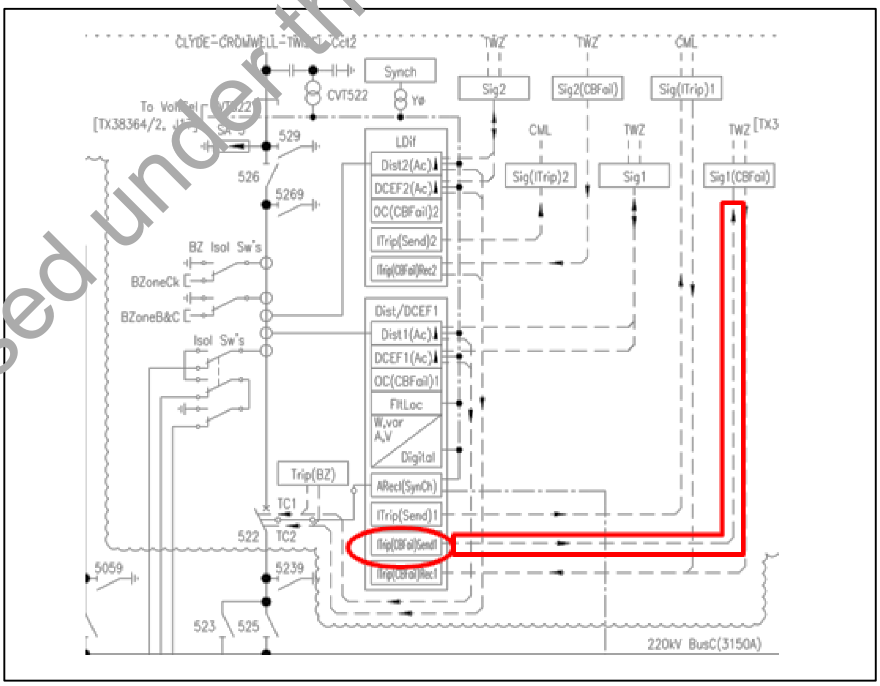
2. Protection circuit diagrams. After observing the protection functionality at a block diagram level the Technician would consult the circuit diagrams to understand the exact workings of the circuitry and how functions can be isolated and tested as needed (typically 15–20 A3 drawings per circuit breaker).

3. Protection settings files and design reports. These are provided by the designer and contain things such as overview reports and spreadsheets with many lines of setting codes/data

4. Station Information folder (Operator notes). This document is specified in TP.SS 01.13 and contains a large volume of information. For protection equipment it is required to contain information such as "How is tripping isolated?"

5. Other. This would include specific drawings, logic diagrams, manufacturer handbooks and the like.

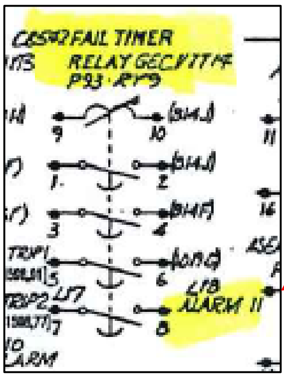
For the Clyde bus zone and CB fail WMS preparation the Technicians first consulted the R & I diagram. He observed the intertrip to Twizel originating from within the line protection. With no bus zone CB fail initiation input into the Twizel line protection shown, he concluded that the ITrip (CBfail) was contained completely within the line protection. He noted that CLD-CRM-TWZ 1 had a note saying "CB fail from external timer not shown". He puzzled over why one circuit had this note.



It is noteworthy that the specification guiding the requirements for relay and instrument diagrams has been updated to require CB fail initiate paths to be shown with a broken orange line.

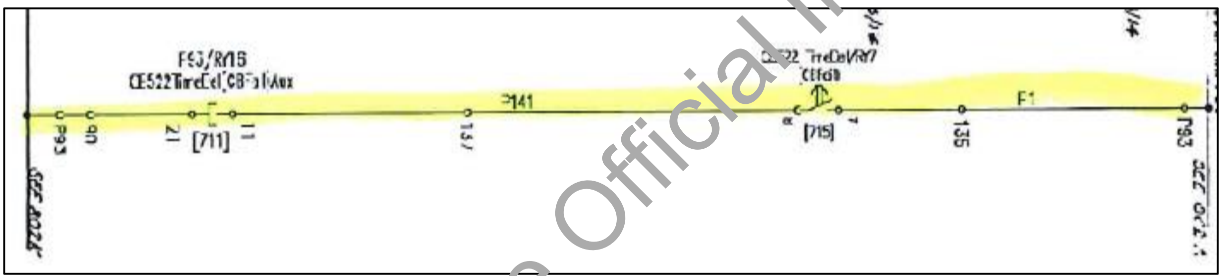
Next the circuit diagrams were consulted. These are original drawings from 1984 marked up for work done since. Old drawings marked up are more difficult to read and gain an understanding of the circuit functionality.

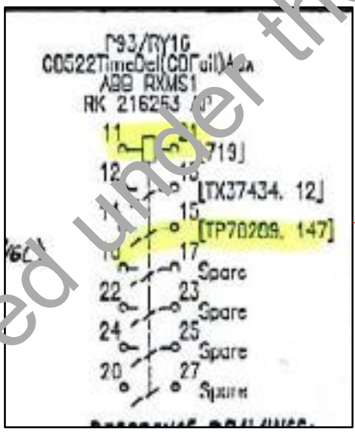
For CLD-CML-TWZ-1 the altered use of the contact was not shown.



This contact is now used to drive an auxiliary relay to provide contacts for the bus zone CB fail intertrip.

For CLD-CML-TWZ-2 the modification to the circuitry is shown, see drawing below:





These contacts are used for the bus zone CBfail intertrip modifications. Other drawings need to be consulted to understand the function.

After consulting the circuit diagrams and preparing an operating sequence for the isolations he had identified, the Technician felt he had what he needed. He further consulted the operator notes in case there was anything helpful. These had no relevant information. No further information was sort.

The maintenance service provider has an expectation that information about new equipment installed by projects will be add to the substation information folder (as required by TP.SS 01.13). The Clyde substation folder has no information about the bus zone CB fail equipment.

The Service Provider has a low level of confidence that the operator notes will be up to date and reliable.

7. Service Providers Competency(s) and Work Control Documentation

The Safety Manual Electricity Industry (SMEI) requires that appropriate precautions are taken to safely control the access to work on equipment. For work of this type a Minor Works Management System is required to be used. (SM-EI 3.305). Transpower has set out its requirements for Minor Work Management Systems in document TP. SS 06.56 (September 2016) Work Authority procedure.

This document was produced in response to Transpower concern of the risk to security of supply posed by the increasing complexity of protection systems and the need to maintain consistent best practice across Service Providers. These requirements have asserted a step increase in the care needed when working with complex protection systems. For jobs that are of the highest risk, a WMS is required. This requires careful assessment of work required and documentation of actions to be taken to perform the work safely. Particularly, the WMS intends to control the actions needed to operate the necessary devices to isolate the equipment to be worked on from any in service equipment.

Maintenance of the Clyde bus zone and CB fail schemes is considered high risk (by TP.SS 06.56) and required a WMS to be prepared and used to control the work activities. Technician 1 began the compilation of the WMS but passed the job to Technician 2 when it became obvious that he would be unavailable to carry out the work due to project commitments at Twizel. Technician 2 proceeded with the job focusing on compiling the operating sequence that controls the required points of isolation. He had pre planned leave and passed the job to Technician 3 to complete. Technician 3 completed and reviewed the WMS.

None of the three Technicians observed the presence of the bus zone CB fail intertrip that had been recently installed. The intertrip was not clear from the drawings. The initiation of the intertrip from the bus zone does not show on the Relay and Instrument diagram (this was not a requirement until June 2016). Only one of the line protections had a note to draw attention to the intertrip. One of the offending contacts had not been updated by the previous project work. A typical 220 kV protection scheme will have 10 – 20 A3 sized drawings to display the circuitry. Information for the Technician is available from the R & I diagram, the scheme drawings, the relay setting file (typically an excel spreadsheet with many lines of logic code) and from the operator notes.

The requirement to have a WMS was in the early stages of implementation as the Clyde bus zone CB fail outage was being prepared for. Transpower supported the service provider to spend the time needed to compile the WMS that this work required, as directed by TP. SS 06.56.

Upon review all aspects of the job planning were performed as required. The outage planning was in a timely manner. The job was allocated and prepared for with acceptable lead time. The service provider staff are all well experienced with significant industry experience.

Technician 1 and 2 held Electrix authorised power technician competency certificates. Technician 3 does not currently hold a power technician competency certificate. Although he has 35 years industry experience, he had recently re-joined Electrix. His manager had been unable to determine how to comply with Transpower's requirements for deeming him competent. At all times a technician with a competency certificate was on the job ensuring compliance with TP.SS 06.25. Technician 2 and 3 held operating competency certificates.

8. Service Providers Response to the Incident

Upon the tripping of CLD-CML-TWZ 2 the Technicians had no awareness that a tripping had occurred and continued with the task at hand. When CLD-CML-TWZ 1 tripped the noise associated with the load rejection of a Clyde generator caused them to stop work and wonder what had happened. In the relay room where they were working there was no indication of anything untoward having happened. The Technicians enquired of the Contact Energy operator what had happened, at that stage he was unaware.

On site in the 33 kV switch room Transpower has a “Realflex” SCADA HMI. The service provider had been advised not to use this system for operating and that it was not being kept up to date. The Technicians observed from the HMI screen that there was no power flow on the Twizel lines but were not able to determine the cause, they assumed something had occurred at Twizel as they were aware project work was ongoing there. At this point they offered assistance to NGOC and stood down from their work.

They were subsequently informed when a protection engineer contacted them to explain and discuss the scenario which had just occurred.

9. Comments on Manual Synchronising

Clyde power station has been provided with the equipment to allow for it to be used as a 220 kV synchronising point should the Waitaki and Clutha valleys become disconnected. With subsequent automation and equipment upgrades this capability has been retained. The Transpower Automatic synchronising project has added the equipment needed for automatic synchronising under certain configurations at Clyde.

The manual synchronising equipment appears upon visual inspection to be all serviceable and consists of a synchronising trolley which can be wheeled to the selected circuit breaker protection panel in the Transpower relay room and plugged in to suit the point of reconnection.

The manual synchronising process would be (in brief):

1. Select the circuit breaker most convenient to be the reconnection point. Carry out switching to provide the required configuration.

2. Plug the synchronising trolley into the sockets to suit the scenario (e.g. upper south island the running frequency and lower south island the incoming frequency).

3. Establish a telephone connection to the generator selected as the frequency keeper in the incoming island.

4. Raise/lower speed and voltage until a match is achieved as indicated on synchronising trolley meters.

5. Close selected circuit breaker.

6. Re-establish normal system configuration.

Use of Synchronising Trolley

The provision of a manual synchronising operating service has been provided for in TP.SS 02.41, Station Inspections. A service code SI0022 and a brief scope intend that the service is provided at Clyde for the two Twizel and two Roxburgh circuits. This specification intends that the service be provided by the incumbent maintenance contract.

This service has not been requested of Electrix.

10. Comments on Outage Request Process for Bus Zone CB Fail

Before the service provider can gain access to work on the bus zone and CB fail schemes they must be approved for release from service via the outage request process. This requires the service provider to determine the equipment required and dates for the work to be done. This is loaded into the outage planning system (IONS) and subsequently declined or approved by Transpower's Outage Planning Engineer.

This process allows for the impact of the equipment outages on the power system to be analysed. Work will not be able to proceed where these impacts are untenable.

Transpower requires that (TP. SS 03.00 HV Power system protection maintenance):

E6 Precautions – bus zone and CB fail protection isolation

E6.1 Testing of the bus zone protection should only be undertaken under the following conditions:

(a) Fine weather;
(b) The entire bus zone protection removed from service;
(c) Outgoing trips isolated;
(d) No exercising of primary plant within the protected zone during the outage;
(e) No live line work being undertaken on any circuit associated with the bus zone protection scheme removed from service, and

Current practise is that these are the conditions required to be met.

No consideration is given to the risk of the impact of the work to adjacent assets or indeed the power system. This approach assumes that the risk of an error occurring while the assets are out of service is not material.

It is current practice for outage requests for certain equipment to require review by a protection engineer. This maybe for example when one protection set of a duplicated scheme is being released from service but the primary asset remaining in service. This review is intended to ensure that the performance parameters of the remaining protection is acceptable.

11. Conclusions/Contributory Factors

1. The design for the bus zone CBfail intertrip modification that was added at the time of automatic synchronising capability did not allow for the isolation capability needed to carry out maintenance safely. The ability of the Technician to understand the design and work on it safely was made difficult and unintuitive.

2. The Technician made reasonable efforts to research the design and prepare an appropriate isolation plan (operating sequence). There was information presented which may have led to the discovery of the modified design had it created sufficient concern in the Technicians mind. He felt he had researched the design sufficiently and completed the WMS.

3. The WMS had uncertain document control and it was unclear whether a peer review had been carried out.

4. Information provided to the Technician was of a low quality. The lack of a CBfail initiation path on the R & I diagram, the errors, age and quality of the circuit diagrams and the lack of any project handover/operator notes made it more difficult for the technician to carry out the work safely.

5. The expectation of Transpower's designers of what information is to be provided to the maintenance Service Provider is not matched to what the Service Provider is expecting.

6. The lack of any indication in the Clyde relay room, that an event had occurred, meant that the chance to avoid tripping the second circuit was lost.

7. Lack of preparedness for manual synchronising at Clyde meant this service was not available to the operator to consider as a restoration option.

8. No consideration of the impact of coincident outages of NAS-LIV-1 and CLD bus zone CB Fail meant the opportunity to consider whether the risk was acceptable was lost.

2 March 2017 South Island AUFLS event

Transpower's final reporting and action list

Transpower has completed its investigation into the 2 March 2017 South Island automatic under-frequency load shedding (AUFLS) event

1.1 On 15 June 2018, Transpower provided the Authority with:

a) its final investigation report (Appendix A)

b) associated action list (Appendix B).

1.2 Transpower plans to publish both reports in July and provide regular progress updates as it works through completing the open actions.

1.3 Authority staff suggest that Committee members ought to read the body of the final investigation report (pages 1 – 28 of Appendix A) and all of the action list in Appendix B.

1.4 It has taken substantial effort by both Transpower and Authority staff to get to this point. Both organisations have committed to reviewing relevant processes so that reporting against future events is not so drawn out and convoluted. John Clarke, GM Operations (Transpower) and Rory Blundell, GM Market Performance (Authority) will be leading this review.

1.5 Transpower representatives will provide a verbal update at the meeting on improvements it has made to the investigation report and how lessons from this event are leading to improvements in future.

The investigation report now has a robust set of actions

1.6 Authority staff have given substantial feedback to Transpower on its investigation report. We have summarised these into the following themes:

a) The handovers of both the protection equipment at Clyde and the re-synchronisation tool from design and build to operation were inadequate. This raises concerns about how widespread this problem may be within Transpower and how many key systems and tools may be impacted.

b) The situational awareness of the technician at Clyde, the National Coordination Centre (NCC) and the National Grid Operating Centre (NGOC) was lacking at different points during the event. This raises concerns about capability and training of security coordinators in coping effectively with stressful events.

c) Consequently, there appears to be opportunities for improvement with staff training, specifically on dealing with stressful situations, verbal operational communications and the re-synchronisation tool. For example, simulator training for the NCC and NGOC staff needs to reflect the high pressure environment of real events, incorporate the use of SPD as a security tool and all the necessary tools that may be used to restore the grid.

d) A series of risk controls failed. This, together with other significant events, raises concerns about the effectiveness of Transpower's risk management systems and their application to HILP events in particular.

e) The event has taken far longer to report on than similar events in overseas jurisdictions.

f) The security implications, extra work-arounds and problems as a result of SPD not reflecting the physical power system. The dispatch model is a valuable security tool to assist stabilising a severely disrupted grid but must be updated to reflect the physical power system so as to avoid producing dispatch solutions that put the power system at risk and/or make safe recovery difficult.

g) The investigation report could be more transparent on the impacts and problems with the dispatch during restoration—generation was dispatched down where the frequency was low, and up where the frequency was high.

1.7 Authority staff consider that:

a) the Transpower report still portrays aspects of the event in an overly positive light

b) Transpower has taken account of our main concerns

c) the six new actions (Actions 7 to 10, and Actions 12 to 13 in Appendix B) provide sufficient comfort that lessons from this event should lead to positive outcomes for consumers in the future.

1.8 The following new actions are particularly significant:

a) Action 7: Review procedures across Transpower regarding handover of tools and systems to ensure the tools and systems are able to be effectively operationalised

b) Action 8: Investigate improvements in the design and use of the market model and market system to assist in the management of large scale system restoration events

c) Action 12: Identify, review and address performance of risk management controls, specifically focused on high impact low probability event interactions.

1.9 Authority staff consider that these actions will lead to lasting and significant improvements to system operations and security of supply.

There are several ways in which this event will continue to get oversight

1.10 As displayed in Appendix B, there are a number of actions in various states of progress.

1.11 Transpower has undertaken to make public its progress towards completion of these actions. This provides a transparent basis for the Authority, and other stakeholders, to monitor Transpower's progress. This is a similar monitoring approach to that the Authority took following the fire in the Penrose substation in 2014.

1.12 Authority staff will monitor Transpower's progress to complete its actions. Authority staff will advise the Authority Board on staff's monitoring, the major event review discussed in 1.4, and action plan against advice received from the Security and Reliability Council (SRC).

1.13 The Authority's Compliance Committee will consider opening investigations into breaches alleged against Transpower in relation to the 2 March 2017 event. Transpower agrees it has breached all except one of those alleged breaches.

1.14 The SRC will be updated on the existence of the final investigation report and action list. The SRC may ask to receive further reporting on the event. In that event, the Authority Board would receive further advice from the SRC.

Action	Accountable	Assigned to	Due	Status
1. Agree an approach, to be used in future, by protection designers and technicians, to enable access to site-specific information on protection schemes	[redacted]	[redacted]	June 2018	On track
2. Develop a process that supports protection designers in gaining clarity on isolation, testing and maintenance requirements for future protection schemes early in the design process - allowing for appropriate consultation with protection technicians who will be undertaking the work	[redacted]	[redacted]	June 2018	On track
3. Consider providing real-time SCADA data to technicians	[redacted]	[redacted]	Dec 2018	Not started
4. Improve current outage planning processes to include a risk based approach that assesses requests for outages of protection equipment to identify maintenance activities that have a high system impact (including the impact of other concurrent planned outages)	[redacted]	[redacted]	June 2018	On track
5. Review the existing Autosync tool and procedures to support NGOC grid asset controllers and NCC system co-ordinators working under pressure	[redacted]	[redacted]	June 2018	On track
6. Re-emphasise and embed through regular training of NGOC and NCC staff the importance of compliance with policies and use of procedures during restoration after rare events	[redacted]	[redacted]	May 2018	Complete
7. Review procedures across Transpower regarding handover of tools and systems to ensure the tools and systems are able to be effectively operationalised	[redacted]	[redacted]	Dec 2018	Not started

8. Investigate improvements in the design and use of the market model and market system to assist in the management of large scale system restoration events	[redacted]	[redacted]	Dec 2018	Not started
9. Work with industry and real-time teams within Transpower to address issues with operational communications	[redacted]	[redacted]	Dec 2018	On track
10. Work with generators to assess what real-time information could assist them with visibility of the system during events and investigate the practicability of providing this	[redacted]	[redacted]	Dec 2018	On track
11. Require technicians testing and maintaining protection schemes to document in their Work Method Statement how, at each stage of their testing process, they will affirm no adverse outcomes have occurred as a result of their work.	[redacted]	[redacted]	May 2018	Complete
12. Identify, review and address performance of risk management controls, specifically focused on high impact low probability event interactions.	[redacted]	[redacted]	Dec 2018	On track
13. Review Transpower's processes for reporting of major power system events, compliance breaches and material failures by Transpower to comply with its own standards and procedures.	[redacted]	[redacted]	Dec 2018	Not started

Action One

Action: Agree an approach, to be used in future, by protection designers and technicians, to enable access to site specific information on protection schemes		
Assigned to: [redacted]	Due Date: June 2018	Status: On track

- Actions assigned by NERG (National Event Review Group) to [redacted] 8 December 2017
- Action recorded in Resolve database (ACT0602)

Action components		Component progress
• Confirm the purpose of existing and newly required documentation and how it fits into a wider documentation structure, identifying linkages to existing systems and processes.	[redacted]	On track
• Workshop a solution with impacted stakeholders including designers, technicians, operators, the SO, and the NGOCs, developing a set of templates for site specific information based on learnings. (Workshops 24 May, 7 June)	[redacted]	Complete
• Investigate methods for Service Providers to review site specific queries and information added by designers.	[redacted]	Complete
• Investigate corporate IT system/platform requirements, identifying an accessible system for the logging and sharing of information (may include Stationware, Maximo, and Echo).	[redacted]	On track
• Agree ownership of agreed system and information (including the maintenance of information), confirming roles and responsibilities.	[redacted]	On track
• Create a change and implementation plan.	[redacted]	On track

Action Two

Action: Develop a process supporting protection designers gain clarity on isolation, testing and maintenance requirements for future protection schemes early in the design process - allowing for appropriate consultation with protection technicians who will be undertaking the work.		
Assigned to: [redacted]	Due Date: June 2018	Status: On Track
• Actions assigned by NERG (National Event Review Group) to [redacted], 8 December 2017 • Action recorded in Resolve database (ACT0603)		
Action components		Component progress
• Work with designers and service providers to define an agreed list of minimum interface requirements for new protection schemes. (Workshops 24 May, 7 June)	[redacted]	Complete
• Develop a set of design principles for the validation/accreditation of the design and construction of new schemes.	[redacted]	
• Confirm a method of displaying the technical aspects of protection systems being installed (Linked to Action 1).	[redacted]	
• Compile a document that describes the proposed process and present at a forum for designers and service provider technicians.	[redacted]	
• Develop changes and create an implementation plan.	[redacted]	

Action Three

Action: Consider providing real-time SCADA data to technicians			
Assigned to: TBD	Due Date: Dec 2018		Status: Not started
• Action to be assigned by [redacted]			
Action components			Component progress
• Consider providing real-time SCADA data to technicians		TBD	Not started

Action Four

Action: Improve current outage planning processes to include a risk based approach that assesses requests for outages of protection equipment to identify maintenance activities that have a high system impact (including the impact of other concurrent planned outages)		
Assigned to: [redacted]	Due Date: May 2018	Status: Complete
• Actions assigned by NERG (National Event Review Group) to [redacted] 8 December 2017 • Action recorded in Resolve database (ACT0613) • Identified that action requires involvement of Grid Performance [redacted]		
Action components		Component progress
• Confirm plan for improving current outage planning process (31 Jan)	[redacted]	Complete
• Review effectiveness of regular SO/GO meetings for identifying major protection outage concurrencies and protection issues, and protection group's involvement in Annual Outage Plan review. (28 Feb)	[redacted]	Complete
• Identify protection outages which involve increased risk and significant impact, update IONS with information for the relevant outage blocks (29 March)	[redacted]	Complete
• Agree processes and responsibilities for using this information	[redacted]	Complete
• Develop process for updating information	[redacted]	Complete
• On-going related work continuing in parallel determine which outage blocks require protection advice	[redacted]	Complete
• Implement Communication Plan on changes, core teams by end of April, wider communication by end of May	[redacted]	Complete

Action Five

Action: Review the existing Autosync tool and procedures to support NGOC grid asset controllers and NCC system co-ordinators working under pressure		
Assigned to: [redacted]	Due Date: June 2018	Status: On track
• Actions assigned by NERG (National Event Review Group) to [redacted] 8 December 2017 • Action recorded in Resolve database (ACT0615)		
Action components		Component progress
• Discussions with NCC facilitated to find a clear outcome that is technically and operationally fit for purpose	[redacted]	Complete
• Tool Interface solution being developed by NCC [redacted] – Options provided for business case completion	[redacted]	Complete
• Implementation of tool interface changes	[redacted]	On track
• Technical Protection changes proposed • Sync-Lock functionality on the relay to be discussed with TP Protection Functions meeting	[redacted]	On track

Action Six

Action: Re-emphasise and embed through regular training of NGOC and NCC staff the importance of compliance with policies and use of procedures during restoration after rare events		
Assigned to: [redacted]	Due Date: Dec 2018	Status: On track
• Actions assigned by NERG (National Event Review Group) 8 December 2017 • Action recorded in Resolve database (ACT0616) • Action passed from [redacted] May 2018 with Operations Division creation		
Action components		Component progress
• Develop and refine single shared Autosync operational documentation and checklist • Role clarifications for NCC and NGOC coordination centres	[redacted]	Complete
• Create simulator experiences for Autosync operation • Complete training of all NCC and NGOC teams through Autosync operations • Capture feedback from all NCC and NGOC staff post simulation to refine documentation	[redacted]	Complete
• Align training schedules for NCC and NGOC teams to allow for integrated training exercises	[redacted]	Complete
• Increase monitoring of operational communications by senior NCC staff during normal operations and during simulator training, to build core competency and ensure Code-compliant communications are being used.	Operations Managers	Complete
• Implement 'human factors' e-learning training material to NCC and NGOC staff.	[redacted]	Complete
• Review policy to ensure clear guidance is provided for changes to Grid Owner offers following asset trips • Reiterate compliance with Manual Reclose Policy (which requires identification of trip causation)	[redacted]	(Jul – Dec) 2018
• Implement HILP-style events into future NGOC training simulations, between July and December 2018 • Include in training reinforcement of policies and procedures used during event management	[redacted]	(Jul – Dec) 2018

Action Seven

Action: Review procedures across Transpower regarding handover of tools and systems to ensure the tools and systems are able to be effectively operationalised		
Assigned to: [redacted]	Due Date: Dec 2018	Status: Not started
• Action assigned by [redacted] June 2018		
Action components		Component progress
• Review procedures across Transpower regarding handover of tools and systems to ensure the tools and systems are able to be effectively operationalised	[redacted]	Not started

Action Eight

Action: Investigate improvements in the design and use of the market model and market system to assist in the management of large scale system restoration events		
Assigned to: [redacted]	Due Date: Dec 2018	Status
• Action assigned by [redacted] June 2018		
Action components		Component progress
• Investigate improvements in the design and use of the market model and market system to assist in the management of large scale system restoration events	[redacted]	Not started

Action Nine

Action: Work with industry and real-time teams within Transpower to address issues with operational communications		
Assigned to: [redacted]	Due Date: Dec 2018	Status: On track
• Action assigned by [redacted] June 2018		
Action components		Component progress
• Work with industry and real-time teams within Transpower to address issues with operational communications (will include Sept industry workshop with generators; ongoing dialogue and reiteration at industry events)	[redacted]	On track

Action Ten

Action: Work with generators to assess what real-time information could assist them with visibility of the system during events and investigate the practicability of providing this			
Assigned to: [redacted]	Due Date: Dec 2018		Status: On track
• Action assigned by [redacted] June 2018			
Action components			Component progress
• Work with generators to assess what real-time information could assist them with visibility of the system during events. Investigation of industry-wide notification system underway.		[redacted]	On track

Action Elven

Action: Require technicians testing and maintaining protection schemes to document in their Work Method Statement how they will affirm no adverse outcomes have occurred as a result of their work, at each stage of their testing process.		
Assigned to: [redacted]	Due Date: May 2018	Status: Complete
• Actions assigned by NERG (National Event Review Group) to [redacted] 8 December 2017 • Action recorded in Resolve database (ACT0614)		
Action components		Component progress
Review internal AUFL's Reports and Electrix work method statements (22 Jan)	[redacted]	Complete
Assess these reviews against recent issue (17 Sept 2017) of work statements requirement documentation (22 Jan)	[redacted]	Complete
Determine if changes if necessary post review and assessment (12 Feb)	[redacted]	Complete
Develop changes and implementation plan as required (end of May)	[redacted]	Complete

Action Twelve

<table>
<tr><td colspan="4">Action:
Identify, review and address performance of risk management controls, specifically focused on high impact low probability event interactions.</td></tr>
<tr><td>Assigned to: [redacted]</td><td colspan="2">Due Date: Dec 2018</td><td>Status: Not started</td></tr>
<tr><td colspan="4">• Action assigned by [redacted] June 2018</td></tr>
<tr><td colspan="3">Action components</td><td>Component progress</td></tr>
<tr><td colspan="2">• Identify, review and address performance of risk management controls, specifically focused on high impact low probability event interactions.</td><td>[redacted]</td><td>Not started</td></tr>
</table>

Action Thirteen

Action: Review Transpower's processes for reporting of major power system events, compliance breaches and material failures by Transpower to comply with its own standards and procedures.			
Assigned to: TBD	Due Date: Dec 2018		Status: Not started
• Action to be assigned by [redacted]			
Action components			Component progress
• Review Transpower's processes for reporting of major power system events, compliance breaches and material failures by Transpower to comply with its own standards and procedures.		TBD	Not started

1805SYSO1

Memorandum on alleged breaches of various provisions of the Code related to 2 March 2017 event by Transpower New Zealand Limited as the system operator

Prepared by: Alex Ehlert
Senior Investigator

Recommendations

1. It is recommended that the Committee:

(a) **appoint** Alex Ehlert as an investigator on a temporary basis under regulation 12 of the Electricity Industry (Enforcement) Regulations 2010 (Regulations) to investigate the alleged breaches of clauses 7.1A, 7.2A(1), 7.2A(2), 7.2B, 8.5(1)(a), 8.5(1)(b), 8.5(2), clauses 3, 4 and 6 of Technical Code B (TCB) of Schedule 8.3, clause 3 of Technical Code C of Schedule 8.3 of the Code and clause 84 of the Policy Statement

(b) **note**, if the investigation establishes breaches of the Code relating to common quality or security, there may also be a breach of regulation 7(1) of the Regulations, which provides a mandatory obligation on participants to report such breaches of the Code

(c) **note** Compliance considers that the alleged breaches of the Code should be fully investigated first before the Authority decides whether the system operator also breached regulation 7(1)

(d) **note** a participant that fails to comply with regulation 7(1) commits an offence and is liable on conviction to a fine not exceeding $20,000, which would require prosecution action through the courts.

Rationale

2. The Authority alleges that Transpower New Zealand Limited (Transpower) as the system operator breached a number of the provisions of the Code when managing a system restoration event on 2 March 2017. The restoration went wrong, involving the connection of two unsynchronised grid islands.

3. An investigation is recommended to determine the impact, provide transparency of the event to affected participants, allow affected participants to raise any settlement requirements, and provide an opportunity for the system operator and affected asset owners to agree on steps to prevent recurrence.

4. An investigation is also recommended to clarify the system operator's obligations and the scope of its responsibility under the Code and the Policy Statement in case of

another major system event and the consequential restoration process. The system operator denies a number of the alleged breaches. An investigation, and the involvement of other interested parties, will assist to clarify the application of a number of important provisions in the Code relating to the system operator's functions.

Circumstances of the event

5. On 21 May 2018, the Authority alleged that, on 2 March 2017, the system owner breached several provisions of the Code and the Policy Statement.

6. Clause 7.1A sets out the requirement that the system operator carry out its obligations with skill, diligence, prudence, foresight, good economic management, and in accordance with recognised international good practice (generally referred to as operating as a reasonable and prudent system operator).

7. Clause 7.2A1 requires the system operator to dispatch generators in a manner that avoids cascade failure of assets resulting in a loss of electricity to consumers arising from a frequency or voltage excursion, or a supply and demand imbalance.

8. Clause 7.2A(2) requires the system operator to maintain frequency in the normal band.

9. Clause 7.2B requires, when there is a frequency fluctuation, the system operator to ensure that frequency is restored to the normal band as soon as reasonably practicable having regard to all surrounding circumstances.

10. Clause 8.5(1)(a) requires the system operator to re-establish normal operation as soon as possible after an event that disrupted its ability to comply with the principal performance obligations, given the capability of generation, ancillary services and extended reserves.

11. Clause 8.5(1)(b) requires the system operator to re-establish normal operation as soon as possible after an event that disrupted its ability to comply with the principal performance obligations, given the configuration and capacity of the grid.

12. Clause 8.5(2) requires the system operator, when re-establishing normal operation of the power system, to have regard to specific priorities.

13. Clause 3 of TCB of Schedule 8.3 requires the system operator to act quickly and safely during a grid emergency in accordance with TCB, so that the actual and potential impacts of any grid emergency are minimised.

14. Clause 4 of TCB of Schedule 8.3 requires the system operator to use reasonable endeavours to ensure that, if necessary, each participant is advised of any independent action required if there is a grid emergency.

15. Clause 6 of TCB of Schedule 8.3 specifies actions the system operator may take in a grid emergency.

16. Clause 3 of Technical Code C of Schedule 8.3 specifies the general requirements for voice communications between the system operator and asset owners.

17. Clause 84 of the Policy Statement specifies the methodology the system operator must follow to re-establish normal operations. The Policy statement is incorporated in the Code (clause 8.10 of the Code).

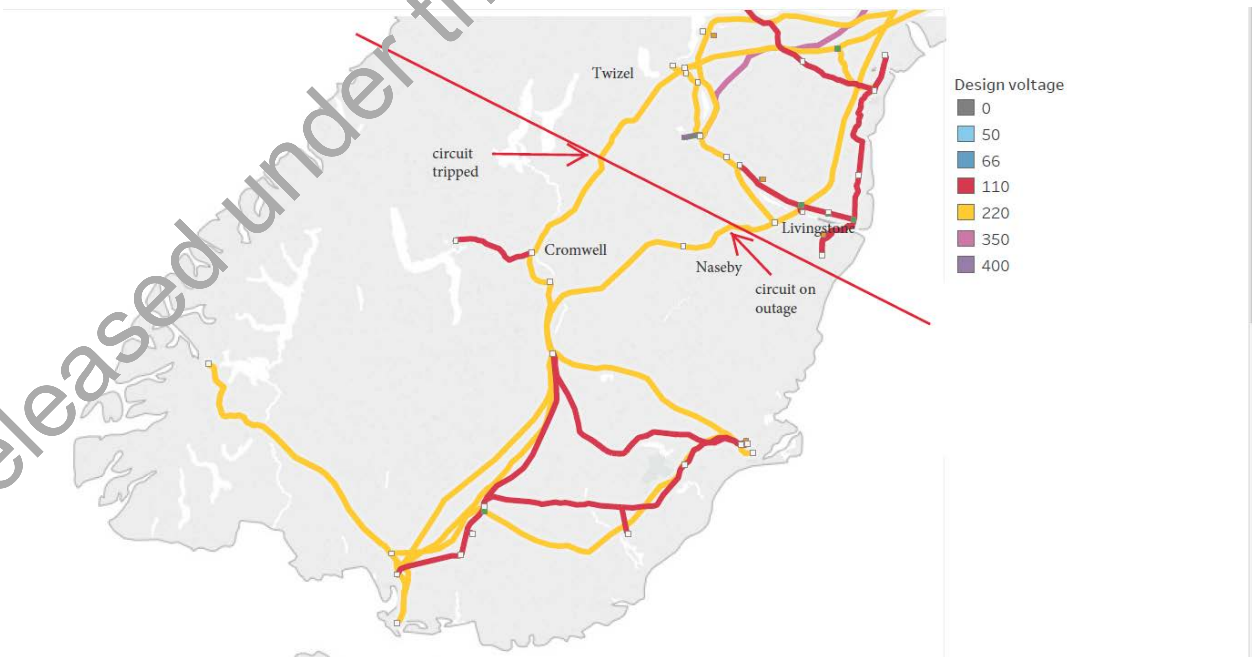
18. On 2 March 2017, the Livingstone–Naseby circuit was out of service for planned maintenance work, leaving the Clyde–Cromwell–Twizel circuits 1 and 2 as the only connections in this part of the grid.

19. On the same morning, the grid owner's technicians were carrying out routine testing of 220 kV bus protection systems at the Clyde substation. The protection work required the 220 kV bus zone and circuit breaker fail protection systems at Clyde to be removed from service.

20. At 11:20, the testing tripped the line circuit breakers at the Twizel substation on the two Clyde circuits causing the lower part of the South Island to be electrically islanded. With the initial imbalances in generation and demand mitigated by the automatic control system responses, the two South Island grid islands each initially returned to near 50 Hz, indicating reasonable balances between reduced levels of supply and demand in each of the two grid islands.

21. An unexpected generation reduction of about 160 MW at Meridian Energy Limited's (Meridian's) Aviemore plant caused the frequency in the upper part of the split to fall again. An incorrect setting in the Aviemore generator governor controls caused the generation output to decrease. Meridian moved quickly to manual control, restoring generation output at Aviemore at 11:28—7 minutes into the event.

Figure 1: Map of electrical island



22. However, during the course of this event, the system operator did not update the scheduling pricing dispatch (SPD) model to reflect the trip of the Clyde–Twizel circuits. This means that the SPD-generated dispatch instructions did not reflect the physical

power system. As a result, the system operator issued dispatch instructions as though the Clyde–Twizel lines were still connected.

23. Shortly after Meridian had resolved the situation at Aviemore, the system operator instructed Meridian to move back to economic dispatch. However, the system operator sent dispatch instructions to South Island generators that were still calculated in SPD as though the circuits were still connected.

24. Meridian's generation controller increased Manapouri generation to comply with the SPD-determined dispatch instruction issued by the system operator, causing the frequency to increase in the lower South Island electrical island.

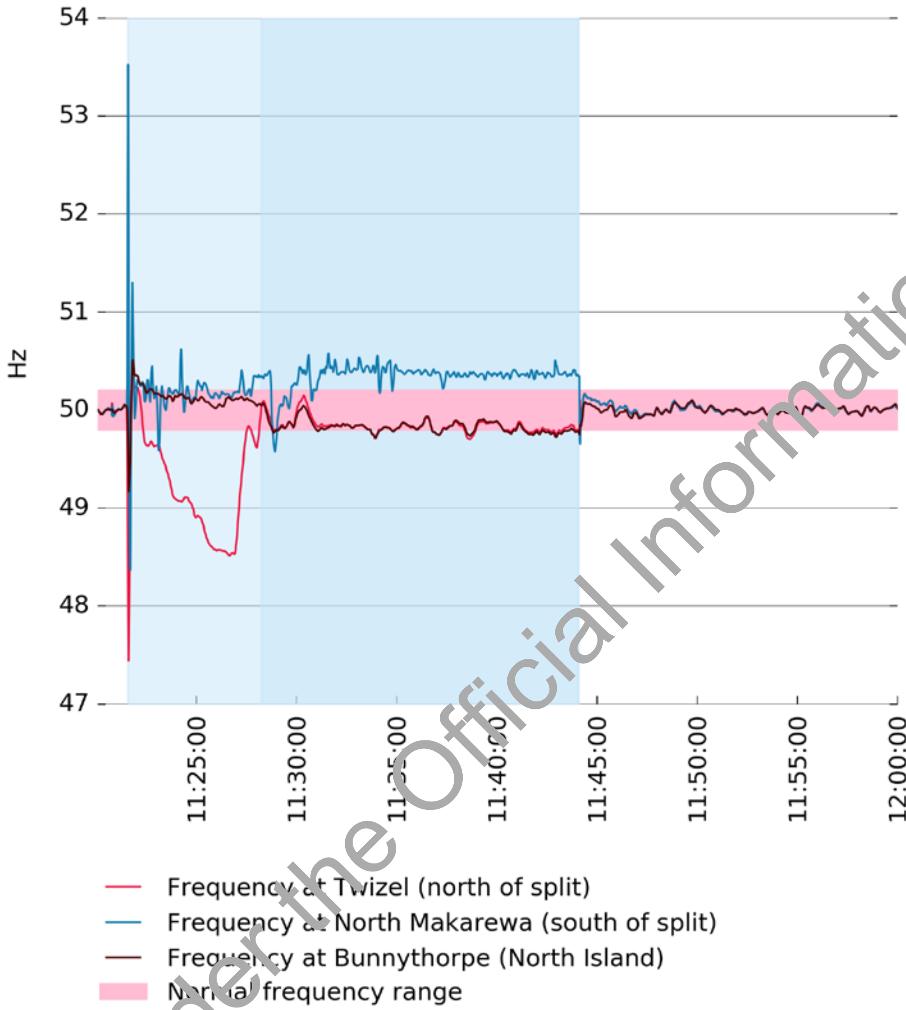
25. Contact Energy Limited's (Contact) generation in the lower South Island electrical island on the Clutha River responded to the increased frequency by backing off generation—the more Manapouri (also in the lower electrical island) ramped up, the more Roxburgh and Clyde generators backed off.

26. Contact's attempts during the event to call the system operator were not answered. The one call that Contact did get through to the system operator's energy coordinator resulted in the energy coordinator telling Contact to "just sit where you are".

27. Independently, Contact's generation controller determined that there must be a split on the South Island grid and so decided to ignore economic dispatch instructions because the frequency was too high. Had Contact followed the dispatch instruction, this would have increased the frequency even further.

28. The system operator continued issuing electronic dispatch instructions and incorrectly dispatching South Island generators. This incorrect dispatch resulted in an over-frequency condition in the electrical island south of the split and an under-frequency condition in the electrical island north of the split.

Figure 2: Grid frequencies



29. During the event, the system operator's security coordinator decided to restore the South Island power system by joining the two grid islands.

30. The system operator's security coordinator orally declared a grid emergency to the grid owner's asset controller, to allow the grid owner to undertake necessary switching operations to enable the use of the auto-synchronising (auto-sync) scheme.[1]

31. The system operator did not re-dispatch South Island generators to align the parameters of the two electrical islands, which were outside the parameters required to safely reconnect the two electrical islands. Despite the misalignment the system operator instructed the grid owner to use the auto-sync function as a step to restore the power system.

32. However, the grid owner's asset controller did not enable the auto-sync function as instructed, and instead closed the circuit breaker without the grid islands being synchronised.

[1] Auto-sync: a tool to check that the parameters of the grid islands are synchronised before re-connection.

33. Transpower's procedure requires following a strict process to restore the power system when using the auto-sync tool. Neither the system operator nor the grid owner used Transpower's process description to manage the restoration using the auto-sync.

34. This first re-connection attempt failed, because the grid frequency in the electrical island south of the split was 0.6 Hz higher than the grid frequency in the electrical island north of it, with a phase angle difference of 120 degrees. A safe reconnection would have required that the two electrical systems needed to be synchronised to:

    (a) a frequency difference of not more than 0.05 Hz

    (b) a phase angle difference of not more than 3 degrees

    (c) voltage within the range of -1% to +5% of nominal voltage.

35. A safe reconnection attempt required the system operator to first re-dispatch South Island generators. This was not done.

36. A minute after the first reconnection attempt failed, the grid asset controller initiated a second reconnection attempt that resulted in reconnection despite a notable frequency mismatch (0.6 Hz) and phase angle difference (60 degrees).

37. The degree of misalignment of frequency and phase angle at the time of this reconnection meant that the generators synchronised to the two South Island grid islands experienced very high levels of rotor electrical torque creating a high risk of damage to generation assets.

Relevant provisions

38. Clause 7.1A provides:

7.1A Reasonable and prudent system operator standard

(1) The **system operator** must carry out its obligations under this Code with skill, diligence, prudence, foresight, good economic management, and in accordance with recognised international good practice, taking into account—

(a) the circumstances in New Zealand; and

(b) the fact that real-time co-ordination of the power system involves complex judgements and inter-related events.

(2) The **system operator** does not breach a **principal performance obligation** or clause 8.5 of this Code if the **system operator** complies with subclause (1).

39. Clause 7.2A provides:

7.2A System operator to maintain frequency

(1) The **system operator** must **dispatch assets** made available in a manner that avoids cascade failure of **assets** resulting in a loss of **electricity** to **consumers** arising from—

(a) a frequency or voltage excursion; or

(b) a **supply** and **demand** imbalance.

(2) Except as provided in this clause and clause 7.2B, the **system operator** must maintain frequency in the **normal band**.

40. Clause 7.2B provides:

7.2B System operator to restore frequency if frequency fluctuation occurs
If a **frequency fluctuation** occurs, the **system operator** must ensure that frequency is restored to the **normal band** as soon as reasonably practicable having regard to all circumstances surrounding the **frequency fluctuation**.

41. Clause 8.5 provides:

8.5 Restoration
(1) If an event disrupts the **system operator's** ability to comply with the **principal performance obligations**, the **system operator** must re-establish normal operation of the power system as soon as possible, given—
(a) the capability of **generation**, **ancillary services**, and **extended reserve**; and
(b) the configuration and capacity of the **grid**; and
(c) the information made available by **asset owners**.
(2) When re-establishing normal operation of the power system under subclause (1), the **system operator** must have regard to the following priorities:
(a) first, the safety of natural persons:
(b) second, the avoidance of damage to **assets**:
(c) third, the restoration of **offtake**:
(d) fourth, conformance with the **principal performance obligations**:
(e) fifth, full conformance with the **dispatch objective**.

42. Clause 3 of Technical Code B of Schedule 8.3 provides:

3 Obligations of all parties

The **system operator** and all **participants** must plan individually and, if appropriate, collectively, for a **grid emergency**, and act quickly and safely during a **grid emergency** in accordance with this **technical code**, so that the actual and potential impacts of any **grid emergency** are minimised.

43. Clause 4 of Technical Code B of Schedule 8.3 provides:

4 Obligations of the system operator
The **system operator** must use reasonable endeavours to ensure that—
(a) if necessary, each **participant** is advised of any independent action required of it if there is a **grid emergency**; and ..

44. Clause 6 of Technical Code B of Schedule 8.3 provides:

6 Actions to be taken by the system operator in a grid emergency
…
(2) If insufficient transmission capacity gives rise to a **grid emergency**, the **system operator** may, having regard to the priority below, if practicable, and regardless of whether a **formal notice** has been issued, do 1 or more of the following:

(a) request that a **generator** varies its **offer** and **dispatch** the **generator** in accordance with that **offer**, to ensure that the available transmission capacity within the **grid** is sufficient to transmit the remaining level of **demand**:
(b) request that an **asset owner** restores its **assets** that are not in service:
(c) request that a **purchaser** or **connected asset owner** reduces its **demand**:
(d) require the **electrical disconnection** of **demand** in accordance with clause 7A:
(e) take any other reasonable action to alleviate the **grid emergency**.

…..

45. Clause 3 of Technical Code C of Schedule 8.3 provides:

3 General requirements for operational communications

(1) Each voice or electronic communication between the **system operator** and an **asset owner** must be logged by the **system operator** and the **asset owner**. Unless otherwise agreed between the **system operator** and the **asset owner**, every voice instruction must be repeated back by the person receiving the instruction and confirmed by the person giving the instruction before the instruction is actioned.

46. Clause 84 of the Policy Statement provides:

Where restoration is required, the **system operator** must use the following methodology to re-establish normal operation of the power system by:

84.1 Addressing any aspects involving public safety.
84.2 Addressing any aspects involving avoidance of damage to **assets**.
84.3 Stabilising any remaining sections of the **grid** and connected **assets** and the voltage and frequency of the **grid**, through the combination of manual **dispatch instruction** and allowing automatic action of **ancillary services** and governor and voltage regulation operation by **generating plant**, and including any necessary disconnection of **demand**.
84.4 Actioning the steps set out in clauses 84.5, 84.6, 84.7 and 84.8 below in the order or in parallel as is judged by the **system operator**, at the time, as most effectively allowing reconnection of **demand**. The order that **assets** are **dispatched** will be influenced by availability, technical, geographic and other factors influencing rapid restoration of **demand**.
84.5 Restoring the transmission, generation, and/or **ancillary service assets** that failed when such restoration assists commencement of steps set out in clauses 84.6 and 84.7, where necessary utilising black start facilities.
84.6 Restoring any disconnected **demand** (which includes any triggered **interruptible load**) at the rate permitted by the security and capability of the available combined generation and transmission system.
84.7 **Dispatching** additional generation and **ancillary services**, where such additional resources are needed to allow **demand** to be reinstated and necessary quality levels to be maintained.
84.8 Seeking revised **offers** where insufficient **offers** exist to achieve the restoration objectives.

84.9 Restoring normal security and power quality of the **grid** system to the levels set out in the **PPOs** and this Security Policy. If the reserve requirements have been set to zero under clause 33A, the actions taken under this clause must include restoring the reserve requirements to the levels set out in the Under-Frequency Management Policy.

84.10 Restoring energy injection levels to the values contained in an updated **dispatch schedule**.

Analysis

Clause 7.1A

47. Compliance considers that the system operator breached clause 7.1A (reasonable and prudent system operator standard).

48. The system operator did not meet the reasonable and prudent system operator standard. It was unskilled and imprudent to embark on any attempt with the grid owner to reconnect the two electrical islands without first addressing the fundamental misalignment/imbalance between the separate grid islands using re-dispatch. The incorrect dispatch increased the risk of asset damage.

49. It is recognised international good practice (and the only acceptable practice) to synchronise electrical systems before connecting assets. The system operator did not try to synchronise the electrical systems at all before embarking on the reconnection attempt with the grid owner.

50. Compliance also considers the system operator did not analyse the situation carefully enough to make informed decisions to determine appropriate actions.

51. The system operator admitted that it did not act reasonably and prudently in the following ways:

    (a) The inter-control room communications were not always clear.

    (b) The system operator's controllers did not follow the procedure for instructing the use of auto-sync.

52. Clause 7.1A(2) provides that the system operator cannot breach the principal performance obligations (clauses 7.2A to 7.2D) or the restoration process under clause 8 of the system operator has complied with the reasonable and prudent system operator standard in clause 7.1A(1).

53. However, the system operator has admitted breaching the principal performance obligations and clause 8.5. This implies that the system operator also considers it did not comply with the reasonable and prudent system operator standard in clause 7.1A(1), in relation to these admitted breaches.

Principal performance obligations (clauses 7.2A to 7.2D)

Clause 7.2A(1)

54. Compliance considers the system operator breached clause 7.2A(1) when it failed to dispatch the South Island generators in a manner that would have avoided cascade failure of assets resulting in a loss of electricity to consumers arising from a frequency excursion or a supply and demand imbalance.

55. The frequency was outside the normal band when the system operator instructed generators to return to economic dispatch. This created a supply and demand imbalance in each of the electrical islands. The system operator should have issued updated dispatch instructions to reflect the system conditions.

56. The system operator denies the breach, because there was no cascade failure and therefore the system operator considers it cannot have breached this provision.

57. Compliance disagrees with this view and considers that clause 7.2A(1) requires dispatch in a manner that avoids cascade failure.

58. An investigation will assist in finding out how other interested parties interpret clause 7.2A(1).

Clause 7.2A.(2)

59. The system operator breached clause 7.2A.(2) when it failed to maintain frequency in the normal band. After the recovery from the Aviemore event, system frequency settled in the normal frequency band. The system operator's subsequent return to incorrect economic dispatch pushed the frequency outside of the normal band.[2] The event is categorised as "other events" under clause 12.4 of the Policy Statement so the principal performance obligations defined for contingent events and extended contingent events under subclauses (5) and (6) of clause 8.2A do not apply.

60. The system operator admitted this breach.

Clause 7.2B

61. The system operator failed to ensure that frequency was restored to the normal band as soon as reasonably practicable having regard to all circumstances surrounding the frequency fluctuation.

62. The system operator admitted this breach and considered that the frequency may have been restored sooner had it initiated better communication with the South Island generators.

Restoration

Clause 8.5(1)(a)

63. Compliance considers that the system operator breached clause 8.5(1)(a) when (after an event that disrupted the system operator's ability to comply with its principal performance obligations) it failed to re-establish normal operation as soon as possible given the capability of generation, ancillary services, and extended reserve. The system

[2] The normal band is defined to be between 49.8 Hertz and 50.2 Hertz (inclusive).

operator could have restored normal operation faster had it used Meridian as a frequency keeper to manage frequency in both electrical islands.

64. The system operator denies the breach because it denies responsibility for the grid owner's action to reconnect without synchronisation.

Clause 8.5(1)(b)

65. The system operator breached clause 8.5(1)(b) when (after an event that disrupted the system operator's ability to comply with its principal performance obligations) it failed to re-establish normal operation as soon as possible given the configuration and capacity of the grid. The system operator dispatching with the Clyde – Twizel circuits modelled as in service using economic dispatch, ignored the actual configuration and capacity of the grid.

66. The system operator admitted this breach.

Clause 8.5(2)

67. Compliance considers the system operator breached clause 8.5(2) when re-establishing the normal operation of the power system. Compliance considers the system operator had insufficient regard to the priorities set out in clause 8.5(2). In particular the system operator had insufficient regard to the second priority, which is to avoid damage to assets. The incorrect dispatch instructions created a situation where the frequencies were so far outside the normal band that they introduced the potential risk of asset damage in case of a reconnection attempt. In addition, the system operator had insufficient regard to the fourth priority, which is the conformance with the principal performance obligations. The frequency was outside the normal band before the first reconnection attempt. Had the system operator appropriately considered this priority it would have stabilised frequency in both electrical islands first before attempting reconnection.

68. The system operator denied this breach. It believes that it gave the correct instruction to the grid owner but the grid owner failed to use the auto-sync tool. Compliance considers this is irrelevant for the application of clause 8.5(2) because the system operator's incorrect dispatch, significantly increased the risk of asset damage in the first instance, and was not in conformance with its principal performance obligations. If the system operator had considered the priorities set out in clause 8.5(2), then the risk of asset damage would have been significantly lower.

Clause 3 of TCB of Schedule 8.3

69. Compliance considers that the system operator breached clause 3 of TCB of Schedule 8.3 when it failed to act quickly and safely during a grid emergency so that the actual and potential impact was minimised. The system operator's incorrect dispatch during the grid emergency increased the risk of damaging connected generators.

70. The system operator denied the breach and believes that it complied with the obligation under this provision. The system operator stated:

(a) *The system operator verbally declared a grid emergency at 11:28 am so the grid owner could reconfigure the South Island grid in preparation for re-synchronisation.*

(b) *The frequencies in the electrical islands stabilised approximately three minutes later and two minutes after that the system operator contacted the grid owner to discuss the re-synchronisation process. These timeframes demonstrate the system operator acted quickly during the grid emergency to minimise the impact of it.*

71. Compliance believes that the system operator's interpretation of its obligation is incorrect. A grid emergency response is not limited to the first and initial response to the event. A grid emergency is related to a particular period and the obligation under clause 3 of TCB of Schedule 8.3 is ongoing. The system operator ended the grid emergency at 12:32 pm. This is when the system operator's obligation to act quickly and safely under this provision ended. The potential risk of asset damage was increased by the system operator's incorrect dispatch during the grid emergency. This constitutes a breach of clause 3 of TCB of Schedule 8.3.

Clause 4 of TCB of Schedule 8.3

72. Compliance considers that the system operator did not use reasonable endeavours to ensure that it advised Meridian and Contact of any independent action required during the grid emergency.

73. The system operator should have advised both generators to take independent action to maintain frequency at within the normal band. The system operator did not do this. The system operator told Meridian three minutes into the event to follow economic dispatch, after first telling Meridian to look after frequency.

74. The system operator denied the breach. The system operator considered:

> *it advised Meridian of the independent action it required Meridian to take (to act as island frequency keeper in each of the USI and LSI) within three minutes of the event. Given the size of Meridian's generating stations it was not necessary to instruct any other frequency keeper to assist.*

75. Compliance considers, after reading the communication transcripts, that the instruction to Meridian was not clear and cannot be interpreted as an instruction to take independent action. Meridian misunderstood the system operator's communication. However, even if it was clear, it would have been ineffective because Meridian's generators were too far off set points.

Clause 6(2)(a) and (e) of TCB of Schedule 8.3

76. Compliance considers that the system operator breached clause 6(2)(a) and (e) when it failed to request generators to vary their offers and to dispatch the generators accordingly, to ensure there was sufficient generation and frequency keeping. It also failed to take any other reasonable action to alleviate the grid emergency.

77. The system operator denied the breach because it believes that this clause is discretionary, rather than placing an obligation on the system operator.

78. Compliance is of the opinion that this clause is not discretionary. The word "may" needs to be read in the context of the whole clause. The clause does not give the system operator the choice to either take action under the clause or to take no action at all.

Clause 3(1) of Technical Code C of Schedule 8.3

79. The system operator did not meet the general sequence requirement for operational communications when communicating with the generators and the grid owner (voice instruction, repeat back, confirm). Miscommunication was the main reason for the issues occurring during the restoration process.

80. The system operator admitted breaching this clause because not all voice instructions were read back and confirmed.

Clause 84 of the Policy Statement (restoration methodology)

81. Compliance considers that the system operator did not follow the required restoration methodology and breached clause 84.2 when it failed to address any aspects avoiding asset damage. The system operator's incorrect dispatch instructions increased the risk of asset damage. Compliance considers that the system operator also failed to stabilise the frequency of the grid through a combination of manual dispatch instructions and ancillary service action. This breached clause 84.3.

82. The system operator denied these breaches. It believes that, because it did not instruct the grid owner to reconnect the two electrical islands, it is not responsible for any risk of asset damage.

83. Compliance is of the opinion that the system operator's incorrect dispatch created the risk in the first instance and that the system operator cannot avoid its responsibility by instructing the grid owner.

84. The system operator also believes that it stabilised the frequency, however, outside of the normal band. Compliance does not agree. The system operator's incorrect dispatch meant that frequency was flat but outside of the normal band for the electrical island south of the split. The obligation under clause 84.3 is for the system operator to take specific actions to stabilise the frequency. The intention of this provision is clearly to get frequency as close as possible to 50 Hz and not to have frequency outside of the normal band.

Impact

85. The actual impact is unknown. However the potential impact was severe ranging from asset damage (as yet undiscovered) to cascade failure.

Actions taken to prevent recurrence

86. The system operator has initiated the following steps to improve performance and to prevent recurrence:

(a) Reviewed the existing auto-sync tool and procedures to support grid asset controllers and system co-ordinators working under pressure.

(b) Assessed controllers' training needs to ensure compliance with policies and use of procedures during restoration after rare events.

(c) Increased monitoring of operational communications.

(d) Provided specific training to perform in high stress situations.

(e) Developed improvements to industry communications in managing events.

(f) Made technical changes to the market system interface.

Previous decisions

87. The system operator has not previously breached any of these provisions.

Other considerations

88. In its fact finding letter dated 21 May 2018, Compliance also asked the system operator why it did not consider reporting potential breaches concerning security, as required by regulation 7(1), or the grid owner's potential breaches under regulation 8(1).

89. The system operator provided the following response:

> *Soon after the event the Authority and Transpower agreed that Transpower would investigate the event internally and produce a full report (being the Transpower Report) in lieu of the Authority carrying out its own investigation under section 16 of the Electricity Industry Act. The grid owner considered it appropriate to wait until the investigation was complete and the report provided to the Authority before reporting any potential breaches of the Code by the grid owner or system operator.*

90. Compliance has confirmed with Market Performance that no such agreement has ever been made. As early as 17 March 2017, Market Performance publicised on the Authority's website that it had instigated an enquiry into the events of 2 March 2017. As an example, the Authority's Chief Executive's letter dated 22 March 2018 to Transpower's Chief Executive stated 'Depending on the outcome of that process the Authority may consult with Transpower on its market performance review into the event, with a view to publishing a separate report'.

91. If a compliance investigation establishes breaches of the Code relating to common quality or security, there may also be a breach of regulation 7(1). This is because the system operator did not self-report its own breaches as soon as practicable after it became aware of them. Alternatively, it may have breached regulation 8(1), if it failed to report another participant having breached the Code. However, regulation 8 has no offence creating provision and the Regulations are silent on how breaches of regulation 8 can be enforced.

Options for the Committee

92. The Committee has the following options with respect to the alleged breaches covered in this report:

(a) decline to take any action on the allege breaches under regulation 11 of the Regulations; or

(b) appoint an investigator to investigate the alleged breaches under regulation 12 of the Regulations; or

(c) require further information to be provided so that the Committee may make a more informed decision.

Compliance paper check sheet

Compliance Committee paper title: 1805SYSO1

Author: Alex Ehlert

Committee meeting date: 28 June 2018

Use this record sheet to confirm that the document meets the Authority's quality standards and compliance procedures. Tick yes, no, or not applicable, as appropriate.

Quality criteria	Yes	No	NA
1. **Compliance processes followed**—all compliance procedures have been followed, including compliance database and file management procedures.	✓	☐	
2. **Recommendation(s)**—are clear and logical, appropriate given the seriousness of the matter, and consistent with the options available to the Committee and its previous decisions.	✓	☐	
3. **Rationale**—a brief discussion of the key reasons why the recommendations are being made.	✓	☐	
4. **Introduction and circumstances**—provides a logical flow of information, includes how the breach was notified and a summary of the factual background.	✓	☐	
5. **Relevant provision(s)**—all relevant Code provisions have been identified.	✓	☐	
6. **Analysis of breach**—provides a clear statement as to how the Code provision was (or was not) breached. Include discussion on the Code provision if problematic.	✓	☐	
7. **Previous decisions**—all relevant previous decisions are referred to concerning the same participant and the same or similar provision, including the timing of those decisions.	✓	☐	☐
8. **Impact**—provide a statement on the actual and potential impact in accordance with the breach assessment criteria. Impact to cover market, operational and security – as applicable.	✓	☐	
9. **Actions to prevent recurrence**—a statement of the actions taken or planned to be taken to prevent recurrence, including the timing for planned actions.	✓	☐	☐
10. **Options**–all available options are identified under the Enforcement Regulations and are consistent with the recommendations.	✓	☐	
11. **Compliance education**–is this a case for compliance education (eg case study)?	☐	✓	☐
12. **Code design**-any Code design issue identified (if applicable). Code amendment proposal included in recommendations.	☐	✓	☐
13. **Written for audience**—presented clearly, logically, and accurately for intended audiences. Noting the audiences may be wider than the Authority.	✓	☐	

Author: Alex Ehlert ______________________ **Date:** 13/6/2018 __

Peer review: Peter Wakefield ______________________ **Date:** 13/6/2018 __

Legal review: ______________________ **Date:** ____________

General Manager review: Ross Hill ______________________ **Date:** 15/06/2018 _

1805GROW1

Memorandum on alleged breaches of clauses 4(5)(b) and 4(6) of Technical Code A of Schedule 8.3 and clause 12.113 of the Code, by Transpower New Zealand Limited as the grid owner on 2 March 2017

Prepared by: Alex Ehlert
Senior Investigator

Recommendations

1. It is recommended that the Committee:

   (a) **appoint** Alex Ehlert as an investigator on a temporary basis under regulation 12 of the Electricity Industry (Enforcement) Regulations 2010 (Regulations) to investigate the alleged breaches of clause 4(5)(b) of Technical Code A (TCA) of Schedule 8.3 and clause 12.113 of the Code

   (b) **decide** that Transpower New Zealand Limited (Transpower) as the grid owner has not breached clause 4(6) of TCA of Schedule 8.3

   (c) **decline** to take action on the alleged breach of clause 4(6) of TCA of Schedule 8.3 under regulation 11(1)(b) of the Electricity Industry (Enforcement) Regulations 2010 (Regulations)

   (d) **note**, if the investigation establishes a breach of clause 4(5)(b), there may also be a breach of regulation 7(1) of the Regulations, which provides a mandatory obligation on participants to report breaches of the Code relating to common quality or security

   (e) **note** Compliance considers that the alleged breaches of the Code should be fully investigated first before the Authority decides whether the grid owner also breached regulation 7(1)

   (f) **note** a participant that fails to comply with regulation 7(1) commits an offence and is liable on conviction to a fine not exceeding $20,000, which would require prosecution action through the courts.

Rationale

2. The Authority alleged that Transpower as the grid owner[1] breached the Code when it connected two electrical grid islands on 2 March 2017. The grid islands were not synchronised, with the connection creating a potentially high risk of asset damage.

3. Transpower admits it breached clause 12.113 by not operating its interconnection assets in accordance with good electricity industry practice. The grid owner denies the alleged breaches of Part 8 of the Code.

4. Compliance agrees with the grid owner that clause 4(6) of TCA of Schedule 8.3 does not apply in this case.

5. An investigation is recommended to determine the impact, provide transparency of the event to affected participants, and provide an opportunity for the grid owner and affected asset owners to agree on steps to prevent recurrence. An investigation is also recommended to consider the application of clause 4(5)(b) of TCA of Schedule 8.3 in the circumstances of such a major system event.

Circumstances of the event

6. On 21 May 2018, the Authority alleged that, on 2 March 2017, the grid owner breached clauses 4(5)(b) and 4(6) of TCA of Schedule 8.3 and clause 12.113 of the Code.

7. Clause 4(5)(b) of TCA of Schedule 8.3 requires a grid owner to provide a means of checking synchronisation before switching assets in locations, that it has agreed with the system operator, so that it is not possible for the switching to result in electrical connecting parts of the New Zealand electricity system that are not synchronised.

8. Clause 4(6) of TCA of Schedule 8.3 requires an appropriate synchronising check facility at an auto-reclose facility at the grid interface, at which there can be power flows into the grid.

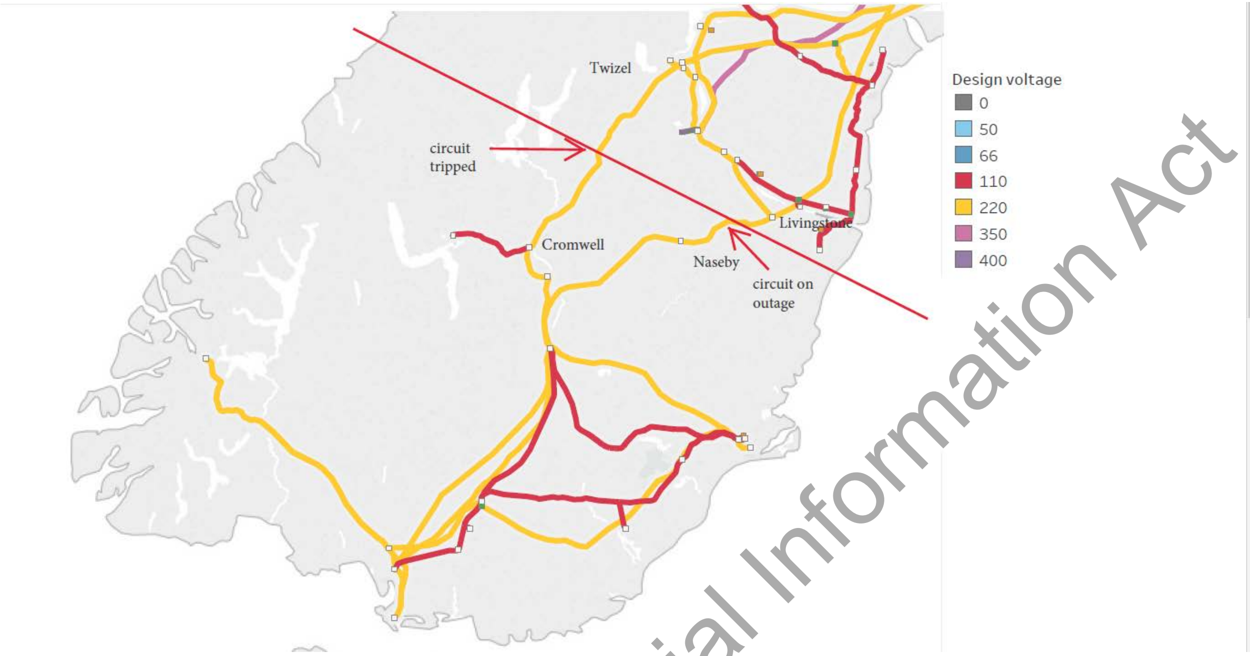
9. Clause 12.113 requires Transpower to design, construct, maintain, and operate all interconnection assets in accordance with good electricity industry practice.

10. On 2 March 2017, the Livingstone–Naseby circuit was out of service for planned maintenance work, leaving the Clyde–Cromwell–Twizel circuits 1 and 2 as the sole connections.

11. On the same morning, the grid owner's technicians were carrying out routine testing of 220 kV bus protection systems at the Clyde substation. The protection work required the grid owner to remove the 220 kV bus zone and circuit breaker fail protection systems at Clyde from service.

[1] On 28 February 2013, the Rulings Panel decided that "Transpower" in rule 5 of section VI of Part F of the Electricity Governance Rules 2003 refers to the grid owner. The wording of clause 12.113 of the Code is identical to the wording used in Rule 5 section VI of Part F. In some places therefore, this paper refers to the grid owner in relation to clause 12.113, for ease of reference.

Figure 1: Map of electrical islands



12. At 11:20, the testing tripped the line circuit breakers at the Twizel substation on the two Clyde circuits, electrically islanding the lower part of the South Island. At 11:28, the system operator's security coordinator decided to stabilise the South Island grid by joining the two electrical islands.

13. The system operator's security coordinator orally declared a grid emergency to the grid owner's grid asset controller. This allowed the grid asset controller to undertake the necessary switching operations.

14. The system operator's security coordinator and the grid owner's grid asset controller decided to use the auto-synchronising (auto-sync) scheme to join the two electrical islands. The auto-sync scheme is provided for the purpose of re-synchronising grid islands before reconnection.

15. The grid asset controller did not enable the auto-sync function but instead initiated a circuit breaker 'close immediate' command to the intended synchronising circuit breaker at Clyde (CYD CB542).

16. This reconnection attempt failed, because the grid frequency in the electrical island south of the split was 0.6 Hz higher than the grid frequency of the electrical system north of the split, with a phase angle difference of 120 degrees.

17. A minute later, the grid asset controller initiated a second re-connection attempt that resulted in reconnection despite a notable frequency mismatch (0.6 Hz) and phase angle difference (60 degrees).

18. The degree of misalignment of frequency and phase angle meant that the generators synchronised to the two South Island electrical islands experienced very high levels of rotor electrical torque. The electrical characteristic resulting from the voltages being 60

degrees out of phase instantly sped up the lower part of the South Island and slowed down the South Island electrical systems north of the split and the North Island system, which instantly exacerbated, at least to some extent, the 0.6 Hz frequency difference. The South Island grid was then ‘wrenched’ back into synchronism, requiring the generators south of the reconnection location to slow down and the generators north to speed up.

Relevant provision

19. Clause 4(5)(b) and (6) of TCA of Schedule 8.3 provides:

> **4 Requirements for grid and grid interface**
>
> **…**
>
> (5) At a **point of connection**—
>
> …
>
> (b) a **grid owner** must provide a means of checking **synchronisation** before the switching of **assets** in locations agreed with the **system operator** so that it is not possible for such switching to result in **electrical connection** of parts of the New Zealand electric power system that are not **synchronised**.
>
> (6) An auto-reclose facility at the **grid interface**, at which power flows into the **grid** can occur, must include an appropriate **synchronising** check facility.

20. Clause 12.113 provides:

> **12.113 Transpower to maintain interconnection assets**
>
> Transpower must design, construct, maintain and operate all **interconnection assets** in accordance with **good electricity industry practice**.

21. Clause 1.1(1) provides:

> **good electricity industry practice** in relation to transmission, means the exercise of that degree of skill, diligence, prudence, foresight and economic management, as determined by reference to good international practice, which would reasonably be expected from a skilled and experienced **asset** owner engaged in the management of a transmission network under conditions comparable to those applicable to the **grid** consistent with applicable law, safety and environmental protection. The determination is to take into account factors such as the relative size, duty, age and technological status of the relevant transmission network and the applicable law

Analysis

22. The Authority considers the grid owner’s actions during this event breached clause 4(5)(b) of TCA of Schedule 8.3. This is because the required means of checking synchronisation did not prevent the re-connection of parts of the New Zealand electricity system that were not synchronised.

23. The grid owner denies the alleged breach and stated:

> *"a means of checking synchronisation was provided for the Clyde-Twizel circuits, namely the auto-sync tool. If the grid owner had enabled auto-sync the electrical islands would not have re-synchronised with the frequencies misaligned. The auto-sync tool is not permanently enabled because it is used very rarely. The tool is not required to be permanently enabled by this clause or any other clause in the Code."*

24. The grid owner's explanation appears to be that the auto-sync tool did provide a means of checking synchronisation to prevent re-connection of parts of the electricity system were not synchronised but it wasn't enabled on 2 March 2017 so clause 4(5)(b) doesn't apply. Compliance does not agree that this is an acceptable interpretation of this clause and an investigation will assist to clarify the application of clause 4(5)(b) in the circumstances of such a major system event.

25. The Authority alleged a breach of clause 4(6) of TCA of Schedule 8.3 because it considered that an appropriate synchronising check facility may have prevented the reconnection.

26. In response, the grid owner denied this alleged breach and stated:

> *"This clause [4(6) of TCA of Schedule 8.3] is about the requirements for an auto-reclose facility. An auto-reclose facility is a feature of a protection system that automatically closes a circuit breaker following an intermittent fault to return the asset to service quickly. The auto-reclose facility at Clyde includes a synchronisation check facility."*

27. Compliance accepts this explanation. The auto-reclose facility at Clyde includes an appropriate synchronising check facility. However, the auto-reclose facility is part of the protection system at Clyde and is not used in the restoration process. Compliance was not previously aware of this.

28. Transpower's operation of its interconnection assets was not in accordance with good electricity industry practice, as required under clause 12.113. It is good electricity industry practice to only connect electrical systems if voltage, frequency, and phase angles are aligned across the synchronising circuit breaker, to avoid the risk of asset damage. Transpower accepted that it breached clause 12.113 by not activating the auto-sync tool as instructed by the system operator.

Impact

29. The impact of these breaches is unknown at this stage. Due to the level of misalignment of the two electrical systems, the possibility of underlying damage to South Island generation plants cannot be ruled out.

30. Affected generators may yet discover asset damage during future maintenance outages, when the units are stripped down for close inspection and routine refurbishment. The event had the potential to reduce expected generator life.

31. However, the grid owner does not believe its actions caused any damage to generators.

Actions taken to prevent recurrence

32. The grid owner has taken the following steps to prevent recurrence:

    (a) reviewed the auto-sync tool and procedures to ensure compliance during restoration

    (b) provided additional training for controllers

    (c) improved communication between system operator and grid controller during normal operation and simulator training

    (d) developed training to manage high stress situations

    (e) investigated the potential to improve communication with participants during serious events.

Previous decisions

33. The grid owner has not previously breached these provisions.

Other considerations

34. In its fact finding letter dated 21 May 2018, Compliance also asked the grid owner why it did not consider reporting breaches of the Code concerning security as required by regulation 7(1).

35. The grid owner provided the following response:

    Soon after the event the Authority and Transpower agreed that Transpower would investigate the event internally and produce a full report (being the Transpower Report) in lieu of the Authority carrying out its own investigation under section 16 of the Electricity Industry Act. The grid owner considered it appropriate to wait until the investigation was complete and the report provided to the Authority before reporting any potential breaches of the Code by the grid owner or system operator.

36. Compliance has confirmed with Market Performance that no such agreement has been made. As early as 17 March 2017, Market Performance publicised on the Authority's website that it had instigated an enquiry into the events of 2 March 2017. In reality, the grid owner and the system operator have always been aware that Market Performance was reviewing the matter. As an example, the Authority's Chief Executive's letter dated 22 March 2018 to Transpower's Chief Executive stated 'Depending on the outcome of that process the Authority may consult with Transpower on its market performance review into the event, with a view to publishing a separate report'.

37. If a compliance investigation establishes a breach of clause 4(5)(b) of TCA of Schedule 8.3 (or any other clause in Part 7, 8, 9 or 13 of the Code), there may also be a breach of regulation 7(1). This is because the grid owner did not self-report its own breaches as

soon as practicable after it became aware of them. Alternatively, it may have breached regulation 8(1), if it failed to report another participant having breached the Code.

Options for the Committee

38. The Committee has the following options with respect to the alleged breaches covered in this report:

(a) decline to take any action on the alleged breaches under regulation 11 of the Regulations; or

(b) appoint an investigator to investigate the alleged breaches under regulation 12 of the Regulations; or

(c) require further information to be provided so that the Committee may make a more informed decision.

Compliance paper check sheet

Compliance Committee paper title: 1805GROW1

Author: Alex Ehlert

Committee meeting date: 28 June 2018

Use this record sheet to confirm that the document meets the Authority's quality standards and compliance procedures. Tick yes, no, or not applicable, as appropriate.

Quality criteria	Yes	No	NA
1. **Compliance processes followed**—all compliance procedures have been followed, including compliance database and file management procedures.	✓	☐	
2. **Recommendation(s)**—are clear and logical, appropriate given the seriousness of the matter, and consistent with the options available to the Committee and its previous decisions.	✓	☐	
3. **Rationale**—a brief discussion of the key reasons why the recommendations are being made.	✓	☐	
4. **Introduction and circumstances**—provides a logical flow of information, includes how the breach was notified and a summary of the factual background.	✓	☐	
5. **Relevant provision(s)**—all relevant Code provisions have been identified.	✓	☐	
6. **Analysis of breach**—provides a clear statement as to how the Code provision was (or was not) breached. Include discussion on the Code provision if problematic.	✓	☐	
7. **Previous decisions**—all relevant previous decisions are referred to concerning the same participant and the same or similar provision, including the timing of those decisions.	✓	☐	☐
8. **Impact**—provide a statement on the actual and potential impact in accordance with the breach assessment criteria. Impact to cover market, operational and security – as applicable.	✓	☐	
9. **Actions to prevent recurrence**—a statement of the actions taken or planned to be taken to prevent recurrence, including the timing for planned actions.	✓	☐	☐
10. **Options**–all available options are identified under the Enforcement Regulations and are consistent with the recommendations.	✓	☐	
11. **Compliance education–**is this a case for compliance education (eg case study)?	☐	✓	☐
12. **Code design**-any Code design issue identified (if applicable). Code amendment proposal included in recommendations.	☐	✓	☐
13. **Written for audience**—presented clearly, logically, and accurately for intended audiences. Noting the audiences may be wider than the Authority.	✓	☐	

Author: Alex Ehlert ______ **Date:** 11/6/2018 __

Peer review: Peter Wakefield ______ **Date:** 11/6/2018 __

Legal review: Andrew Springett ______ **Date:** 14/06/18 ___

General Manager review: Ross Hill ______ **Date:** 14/06/2018 _