

Security and Reliability Council ::: Meeting number 2

Venue ::: Electricity Authority Boardroom, Wellington

Time and date ::: 09.30am to 12.30 pm, Thursday, 18 August 2011

## Agenda

|    | Item                                                                                                                            | Time  |
|----|---------------------------------------------------------------------------------------------------------------------------------|-------|
|    | <b>Welcome and introduction</b>                                                                                                 | 09.30 |
| 1  | Attendance and apologies – Kevin Thompson, <i>Chair</i>                                                                         |       |
|    | <b>Administration</b>                                                                                                           |       |
| 2  | Previous meeting minutes                                                                                                        |       |
|    | a) Minutes from 27 April 2011 – <i>Chair</i>                                                                                    |       |
|    | b) Action arising: Memorandum of Understanding between the Electricity Authority and the Commerce Commission                    |       |
| 3  | Correspondence – <i>Chair</i>                                                                                                   |       |
| 4  | Disclosure of interests – <i>Chair</i>                                                                                          |       |
|    | <b>Papers and Presentations</b>                                                                                                 |       |
| 5  | Proposed SRC Output Programme – <i>Authority</i>                                                                                |       |
| 6  | System Operator Operational and System Performance Dashboard – <i>System Operator</i>                                           |       |
| 7  | Security policy and standards                                                                                                   |       |
|    | a) Transmission planning grid reliability standard – <i>Authority, Bruce Smith</i>                                              |       |
|    | b) System Operation and Grid Planning Standards – <i>System Operator</i>                                                        |       |
|    | c) Security of supply winter capacity and energy margins – <i>Authority, Peter Smith</i>                                        |       |
| 8  | Security and reliability across the industry                                                                                    |       |
|    | a) Risk management – general discussion ( <i>no papers</i> )                                                                    |       |
| 9  | Under-frequency management                                                                                                      |       |
|    | a) Summary of current Common Quality work streams (AUFLS, reserves review and normal frequency review) – <i>System Operator</i> |       |
| 10 | Christchurch earthquake                                                                                                         |       |
|    | a) Feedback on learnings – <i>Transpower, Orion (John O'Donnell, GM Infrastructure)</i>                                         |       |

|    | Item                                                                                                                                           | Time  |
|----|------------------------------------------------------------------------------------------------------------------------------------------------|-------|
| 11 | Rugby World Cup preparedness<br>a) Summary of measures taken to safeguard reliability of supply during the RWC period – <i>System Operator</i> |       |
| 12 | <b>General Business</b><br>a) Next meeting agenda – Chair<br>b) Any other business                                                             |       |
| 13 | <b>Next meeting</b><br>a) December 2011                                                                                                        | 12.30 |
| 14 | <b>Lunch</b><br>a) Served in the Boardroom                                                                                                     |       |

|                                                               |
|---------------------------------------------------------------|
| Security and Reliability Council :: Meeting Number 1          |
| Venue :: Level 7, ASB Bank tower, 2 Hunter Street, Wellington |
| Time and date :: 09:30 :: 27 April 2011                       |

## Draft Minutes

### Present

::: Kevin Thompson (Chair)  
 ::: Tim Lusk  
 ::: Patrick Strange  
 ::: Albert Brantley  
 ::: Bruce Turner  
 ::: Terrence Currie  
 ::: Dennis Barnes  
 ::: David Russell

### Apologies

::: Roger Sutton non- attendance  
 Dennis Barnes lateness

### In attendance

Electricity Authority:  
 ::: Carl Hansen, Chief Executive and principal Authority representative  
 ::: Darryl Renner, Director System Operations and Common Quality  
 ::: Mike Collis, Senior Adviser Common Quality  
 System Operator:  
 ::: Kieran Devine, General Manager (for agenda items 7 and 8)  
 ::: Gari Bickers, Senior Development Adviser (for agenda items 7 and 8)  
 ::: John Campbell, Risk and Performance Manager (for agenda items 7 and 8)

The meeting opened at 09:30.

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#### 1 Attendance and Apology

1. The Chair welcomed members to the meeting and noted apologies from Dennis Barnes for lateness, and Roger Sutton for absence. The Chair granted leave of absence to Roger.

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#### 2 Chair's Introduction

2. The Chair summarised the terms of reference for the Security and Reliability Council (SRC) and drew attention to section 3 of part 1 of the 'Charter about Advisory Groups'. He emphasised that when advising on security reliability of supply issues, the SRC is expected to take a strategic forward-looking view of the industry. It was noted that security of supply encompasses the generation and transmission aspects of the power system and is not limited to the performance of the System Operator. The relevant
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sections of the Charter are presented below:

*"The Authority expects the SRC to take a strategic view, utilising the knowledge and experience of its members.*

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*The Act states that the SRC's function is to advise the Authority. The Act does not provide for the SRC to have Code-making capability, or for the SRC's decisions or deliberations to be binding. Similarly, the Act does not provide for the SRC to have directing rights over the system operator or other industry participants, or to take on responsibilities beyond that of advisor to the Authority (such as a 'spokesperson' type role on security of supply).*

*Given the SRC's function, the Authority recognises that advice it receives from the SRC relating to the system operator is more likely than not to be of value to the system operator. Therefore, the Authority will pass on the SRC's advice to the system operator and/or any other parties involved, unless confidentiality prevents this.*

*When advising on the performance of the electricity system and the system operator, the SRC's focus will be both forward and backward-looking. As part of its function the SRC will be requested to review the system security assessments prepared by the system operator, and review the system operator's performance against its security of supply functions.*

*When advising on reliability of supply issues, the SRC will be expected to place a greater emphasis on looking forward, usually with a focus on the medium (1-5 years) to longer term (5-10 years). This would be the case, for example, when reviewing the system operator's annual security of supply assessments.*

*The SRC must avoid duplicating the Authority's role in assessing the day-to-day performance of the electricity system and the system operator, such as receiving and reviewing regular reports from the system operator required under the Code and the system operator service provider agreement.*

*The SRC will receive six-monthly reports on the performance of the electricity system and system operator. Similarly, it will consider the system operator's medium- to longer-term forecasting of security of supply no more than once every six months.*

*From time-to-time the SRC may be required to advise and/or assist the Authority on specific performance and reliability issues."*

3. The Chair explained that members of the SRC will normally be appointed for a period of three years but the terms of the founding members have been staggered.
4. The Chair reminded members of their obligation to exclude matters from discussion that might contravene part 2 of the Commerce Act.

### 3 Previous Minutes

5. Being the inaugural meeting of the SRC, there were no previous meeting minutes to approve.

### 4 Correspondence

6. There were no items of correspondence received.

### 5 Disclosure of Interests

7. The Chair advised members that any conflicts of interest ought to be disclosed as and when relevant to

discussions held by the SRC.

## 6 Authority Objective

8. Carl Hansen gave a presentation on the Authority's statutory objective. He explained that the Authority's role is to act in the long-term interests of consumers, and that the three limbs of its statutory objective all relate in different ways to efficiency. He noted that both actual and perceived reliability of supply are important and that perceptions about standards of reliability are apt change over time.

## 7 Transmission Tomorrow

*Kieran Devine and members of his senior staff joined the meeting at this point. Kieran introduced Doug Goodwin, Kevin Small, Gari Bicker and John Campbell to the SRC members and briefly explained their respective roles.*

9. Kieran Devine provided an overview of the System Operator organisation explaining the staff numbers and control centre facilities required to support real-time operation of the power system. The System Operator conducts approximately 1.5 million electricity industry Code transactions per annum.
10. The market systems that support the real-time operation of the power system are on the cusp of needing further development although the technological improvements required to support these future development are as yet unclear.

*Doug Goodwin and Kevin Small left the meeting at this point.*

11. Patrick Strange summarised the findings of a study undertaken by Transpower using scenario analysis to investigate the future role of the New Zealand high voltage transmission grid. The study concluded that there will be an ongoing need for the core grid to transfer power between the North and South Islands for the next 50 years.
12. The traditional deterministic (n-1) approach to the design of resilience in transmission grids has been replaced by a probabilistic approach which allows some trade off between the cost of grid security and the cost of non supply. The grid will be operated closer to its stability limit and dynamic capability ratings will progressively replace static ratings. The future grid will require more interactions to take place between generating companies and the Grid Owner, and between loads and the System Operator.
13. It was pointed out that the Code as written assumes a static grid and will need to change over time to adapt to the future grid.
14. A member noted the likely impact of smart meters on grid utilisation in the next five years and enquired about the linkages between Transpower's transmission tomorrow vision and the respective objectives of the Commerce Commission and the Electricity Commission. Carl Hansen advised that the objectives of the Commerce Commission and the Electricity Authority are aligned through a formal memorandum of understanding and this should be circulated to members for information.
15. A member expressed concern about the blurring of the roles between the Grid Owner and the System Operator, both being part of Transpower. It was noted that under the Code the Grid Owner makes a formal offer of its asset capability and the System Operator is entitled to utilise the full offered capability. In other jurisdictions these roles are nearly always integrated, unless there are multiple transmission owners, in which case independent system operators are more common.

*Dennis Barnes arrived at 10:40 and offered his apologies to the Chair for not being able to be present at*

*the start time of the meeting.*

| Action                                                             | By          | Date for action       |
|--------------------------------------------------------------------|-------------|-----------------------|
| Copy the Commerce commission/Electricity Authority MOU to members. | Secretariat | Prior to next meeting |

## 8 Reports

### *Power system performance*

16. Kieran Devine identified the key market structural issues that impact on operational performance of the power system as being:

- The market is a self commitment market and the System Operator has no authority to act beyond the voluntary offers
- The role of the System Operator is to support the economic and social well-being of society
- Market delivery processes tend to be 'just in time' and there is a belief that the market will efficiently solve all delivery issues without intervention
- The grid is being run closer to its capacity limits and more active management by the System operator is required
- While the power system is planned to a probabilistic standard, it is operated in real time to maintain supply with resulting increases in risk at times when energy and capacity offers are short
- Smart grids and smart meter technology will impact on system operations
- The grid and distribution network control centre structure is likely to change in the future from the present three level structure to a two level structure with a lesser number of control centres – possibly two grid level and five distribution level centres
- There is a need to maintain a close working relationship with the Electricity Authority to manage strategic changes within the limits of available technology and resources

### *Security of supply*

17. Gari Bickers explained that from 1 November 2010 the System Operator took over operational responsibility for the policies on emergency management and supply forecasting. The System Operator is currently using policies inherited from the Electricity Commission. The System Operator's main obligations are to publish a weekly security of supply report comprising the hydro risk curve and the risk meter, and the annual security of supply assessment which looks at the capability of generation to meet demand over the next 5 years.

18. As part of its development work, the System Operator plans to review and update the emergency management, supply forecasting policies and the black start standard.

### *System Operator performance*

19. John Campbell explained the processes set out in the Code for the System Operator to carry out an annual self assessment of its performance and for the Electricity Authority to independently assess the System Operator's performance. Its performance is also assessed contractually under the System Operator Service Provider Agreement and there is a need for co-ordination of performance assessment criteria.

*Joint Work Plan*

20. John Campbell described the joint work plan that has been developed with the Electricity Authority and the larger internal System Operator plan that sits behind the joint work plan. It is expected that there will be a two-fold increase in development work in the next year.

9 **Next Meeting**

21. The next meeting is scheduled for 18 August 2011.
22. The Chair outlined the following as topics he would like to be discussed at the next meeting:
- Is the value of expected un-served energy (currently \$20,000/MWhr) the level of security of supply that the SRC is prepared to accept?
  - Security and reliability relates not just to the System Operator and the Grid owner but also to generation and distribution companies - what risk management systems do the generation and distribution companies represented on the SRC have in place for secure and reliable operation?
  - What learnings have been taken from the Christchurch earthquakes -what worked very well and what could have been done better, both of which should be of value to the industry. (Transpower and Orion)
  - What are the power system security related issues for the rugby World Cup and how is the industry preparing for the event? (System Operator)

| Action                                                                                       | By      | Date for action |
|----------------------------------------------------------------------------------------------|---------|-----------------|
| Respective members to be prepared to talk to the above topics at the next meeting in August. | Members | By next meeting |

10 **Other Business**

23. Patrick Strange advised the Council that Siemens has encountered a delay in manufacturing the control system for the HVDC Pole 3 and that impact on the planned commissioning date for Pole 3. Any delay would result in a review of the planned decommissioning date of Pole 1.
24. Carl Hansen advised that the Authority would produce a dash board of security targets and achievement statistics for the next meeting and would circulate relevant background papers.
25. Tim Lusk noted that it would be valuable for the Council to get an early understanding of the program of work ahead based on the Electricity Authority's current view of matters that the Council could add value to, given their terms of reference. He observed that the joint work programme looked ambitious and would need close co-ordination between the System Operator and the Authority. The Chair noted that the SRC members also need to proactively challenge existing assumptions, systems, procedures and practices which may be a threat to supply security and reliability, and not only respond to matters presented to them for consideration.

*The meeting closed at 12:40*

| Action                                                                                                                        | By          | Date for action |
|-------------------------------------------------------------------------------------------------------------------------------|-------------|-----------------|
| The Authority to produce a dash board report for the next meeting and circulate background security and reliability papers to | Secretariat | Prior to next   |

members.

meeting

# Memorandum of Understanding between the Electricity Authority and the Commerce Commission

December 2010

## Contents

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This **Memorandum of Understanding** (memorandum) is made on the *9<sup>th</sup>* day of *December* 2010

**between** (1) **Electricity Authority** (the Authority)  
**and** (2) **Commerce Commission** (the Commission)

## Background

- 1 The Authority is an independent Crown entity established under section 12 of the Electricity Industry Act 2010, and is the regulator of the electricity industry. The objective of the Authority, as set out in section 15 of the Electricity Industry Act, is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.
- 2 The Commission is also an independent Crown entity established under section 8 of the Commerce Act 1986. The Commission has certain functions, powers and duties in relation to the electricity industry, particularly (but not exclusively) under Part 4 of the Commerce Act. The Commission's jurisdiction under Part 4 includes setting regulation of the price and quality, and information disclosure requirements, for goods or services regulated under the Commerce Act.

## Purpose

- 3 The Authority and the Commission recognise that they share certain common interests in relation to their respective statutory functions with regard to the electricity industry. This memorandum explains how the Authority and the Commission intend to coordinate their respective roles under the Electricity Industry Act and the Commerce Act.
- 4 Nothing in this memorandum is intended to limit or affect the independence of each party or the requirement that each party act to fulfil its legal functions and obligations.

## How we will work together

- 5 The Authority and the Commission will work closely together in the spirit of this memorandum to ensure that their respective roles are well coordinated, and to minimise any scope for uncertainties regarding jurisdictional issues.
- 6 The Authority and the Commission agree that there are a number of principles which will govern the relationship under this memorandum. Specifically, but without limitation, the two parties agree to:

- a. work together to coordinate activities to avoid potential overlaps or duplication of effort between the parties, and to maximise efficiency and effectiveness;
  - b. keep each other informed in a timely manner on any matter that may affect the other party's roles and/or responsibilities, powers and/or functions;
  - c. work together to clearly communicate our respective roles and responsibilities to stakeholders and minimise the potential for confusion in that regard;
  - d. share information, knowledge and skills to increase the overall capability of both parties;
  - e. adopt a no surprises approach, by advising each other early of any identified issues that might affect the other party; and
  - f. seek to minimise any scope for uncertainties regarding jurisdictional issues.
- 7 Staff from both parties will meet as required to give effect to the requirements of this memorandum.
- 8 This memorandum will be made available on both the Authority's and the Commission's websites.

## Roles and responsibilities in areas of common interest

### Monitoring and promoting competition

- 9 One of the Authority's functions under section 16 of the Electricity Industry Act is to undertake industry and market monitoring. The Authority's objectives for this function are to promote competition, reliability and efficiency in the electricity industry for the long-term benefit of consumers.
- 10 In regard to monitoring competition the Authority's focus is on the competitiveness of electricity markets, rather than on the conduct of any particular market participant or group of market participants. The Authority's focus in promoting competition is on effecting pro-competitive measures through Electricity Industry Participation Code (Code) amendments and market facilitation measures, where doing so is consistent with the Authority's statutory objective.
- 11 The Commission's role under the Commerce Act is to promote competition in markets for the long-term benefit of consumers within New Zealand by prohibiting contracts or arrangements by businesses that could lead to a substantial lessening of competition, the taking advantage of substantial market power to deter or eliminate competition, and mergers or acquisitions that would substantially lessen competition. The Commission enforces, adjudicates and provides information and advice relating to generic competition law that prohibits anti-competitive behaviour and structures in markets. The Commission also conducts regulatory inquiries where there is little or no competition and little or no likelihood of a substantial increase in competition, to determine whether to recommend that goods or services should be regulated.

## Regulating lines services

- 12 The Authority and the Commission acknowledge that from time to time they may have areas of common interest in regard to the regulation of Transpower and any other line owner, particularly with respect to the:
- a) approval of Transpower's grid upgrade plan proposals, including setting and applying grid reliability standards and the value of lost load;
  - b) price and quality of goods and services provided by Transpower;
  - c) pricing methodologies applicable to Transpower or any other line owner; and
  - d) information disclosure requirements that apply to suppliers of electricity lines services.
- 13 Section 52A of the Commerce Act provides that the purpose of Part 4 of the Commerce Act, which relates to controlled goods or services (including electricity lines services), is to promote the long-term benefit of consumers, by promoting outcomes that are consistent with outcomes produced in competitive markets such that suppliers of regulated goods or services:
- a) have incentives to innovate and to invest, including in replacement, upgraded and new assets; and
  - b) have incentives to improve efficiency and provide services at a quality that reflects consumer demands; and
  - c) share with consumers the benefits of efficiency gains in the supply of the regulated goods or services, including through lower prices; and
  - d) are limited in their ability to extract excessive profits.
- 14 The Commission's responsibilities under Part 4 of the Commerce Act include:
- a) determining input methodologies relevant to the various forms of regulation of goods or services under that Part, including an input methodology for Transpower's capital expenditure proposals;
  - b) setting price-quality paths for those suppliers of goods or services that are subject to price-quality regulation;
  - c) requesting and approving grid upgrade plan proposals by Transpower in accordance with:
    - i. the Electricity Governance Rules (as they were immediately prior to their revocation by the Electricity Industry Act) from 1 November 2010 and until the capital expenditure input methodology is determined; and
    - ii. the capital expenditure input methodology once that input methodology is determined.
  - d) monitoring compliance with price-quality paths;

- e) requiring the disclosure of certain information by those suppliers of regulated goods or services that are subject to information disclosure regulation; and
  - f) publishing a summary and analysis of the publicly disclosed information for the purpose of promoting greater understanding of the performance of individual regulated suppliers, their relative performance, and the changes in performance over time.
- 15 The parties agree, that in order to coordinate their respective roles and responsibilities:
- a) the Commission will take into account, before exercising any of its powers under Part 4 of the Commerce Act, the matters specified in section 54V of the Commerce Act, and any Commission requirements relating to Transpower quality standards in a section 52P determination will be based on, and be consistent with, quality standards set by the Authority (as required under section 54V(6) of the Commerce Act);
  - b) the Authority will take into account the price-quality paths set by the Commission in relation to suppliers of electricity lines services, and the information disclosure requirements imposed by the Commission on suppliers of electricity lines services under Part 4 of the Commerce Act;
  - c) the Authority will consult with the Commission where a new or changed rule under the Code may have an impact on or introduce uncertainty surrounding the determinations on price-quality and information disclosure regulation under the Commerce Act; and
  - d) the Authority and Commission will coordinate their respective initiatives in the following areas to ensure that there is consistency in any information requirements to be provided by suppliers of electricity lines services to avoid duplication and imposition of unnecessary administrative costs:
    - i. establishing guidelines for the calculation and management of distribution losses; and
    - ii. developing policies to reduce non-technical losses.

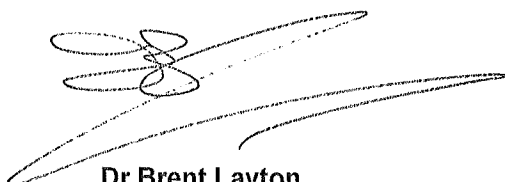
## Term of memorandum

- 16 This memorandum becomes effective when signed by the Authority and the Commission, and remains effective unless terminated by either party.
- 17 This memorandum may be amended at any time during its term by written agreement between the two parties.

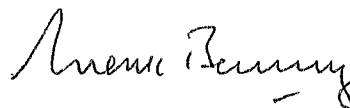
## Issue resolution

- 18 Both parties will use their best endeavours to resolve any issue in a timely manner and in the way that best supports the delivery of the government's strategy and policy, in particular to the long-term benefit of consumers.
- 19 In the event of issues arising between the parties they will be resolved, or if necessary escalated for resolution, in accordance with the following order and timeframe:
- a. the Authority and Commission personnel and, if unresolved within two weeks, then escalated to;
  - b. the responsible managers and, if not resolved within two weeks, then escalated to;
  - c. the Chief Executive of the Authority and the Chief Executive of the Commission, who will agree on what further action is required.
- 20 Solutions to issues need to be consistent with the roles and mandates of each party.

## Signatures



**Dr Brent Layton**  
**Chair**  
**Electricity Authority**



**Dr Mark Berry**  
**Chair**  
**Commerce Commission**

# Delivering the SRC Charter - Proposed SRC output programme

**Prepared by:**

Fraser Clark  
**General Manager Operations Development**

**Discussion and approval**

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11 August 2011

## **Delivering the SRC Charter - Proposed SRC output programme**

### **Recommendations**

1. It is recommended the Security and Reliability Council (SRC) agree to the following programme of regular outputs, consistent with its statutory function:
  - (a) December meeting: SRC report to the Authority Board on the performance of the system operator;
  - (b) April meeting: SRC report to the Authority Board on reliability of supply, including energy and capacity adequacy; and
  - (c) August meeting: SRC report on the performance of the electricity system.

### **Rationale**

2. The Electricity Industry Act 2010 (Act) states the function of the SRC is to provide independent advice to the Authority on
  - (a) the performance of the electricity system and the system operator; and
  - (b) reliability of supply issues.
3. The proposed programme of outputs is consistent with this statutory function.

### **Next steps**

4. Preparation of the first SRC report on the performance of the system operator (to be drafted by the SRC's secretariat for review and approval by the SRC at its December 2011 meeting).

### **Timing and resourcing of the proposed reports**

5. The system operator provides an annual review of its performance to the Authority at the end of September. The timing of the proposed SRC report into the performance of the system operator for the December (or equivalent) meeting allows the SRC's secretariat to reference this self review in the preparation of the report. It will also ensure that the SRC fulfils its review requirements as per paragraph 8(b) above.
6. Under the Code the system operator is required to publish its annual security of supply assessment, looking at least 5 years ahead, by 31 January each year.<sup>1</sup> The timing of the proposed SRC report into reliability of supply for the April (or equivalent) meeting would allow it to reference this assessment. It will also ensure that the SRC fulfils its specific requirements as per paragraph 8(a) and (d) above.

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<sup>1</sup> As per section 1.2 of the Security of Supply Forecasting and Information Policy (SOSFIP).

7. The third report, on the performance of the electricity system, proposed for the August (or equivalent) meeting aligns with the third 'limb' of the SRC's scope.
8. Drafts of each of the reports will be prepared by the SRC's secretariat for review and approval by the SRC. These draft reports will draw on expertise external to the Authority as and when required.

## **Interaction with the Authority Board**

9. The final reports will be provided to the Board of the Authority for consideration and made available to industry participants.
10. The SRC should consider whether high level summaries of these reports should also be prepared for communication to the general public. The Authority Board is likely to favour this approach.
11. Under the SRC's terms of reference the chair may, as required, attend Authority Board meetings to present the SRC's advice (at 5.1). Given the terms of reference also anticipate the SRC meeting with the Authority Board on an annual basis (at 7.3), it may be that the presentation of one of these reports could be aligned with this meeting.

## **Other SRC activities**

12. In addition to completing these reports the Electricity Authority (Authority) also expects the SRC to advise on the performance of the electricity system and the system operator, and on reliability of supply issues, identified by the SRC and/or the Authority.

## **Background**

13. The Authority's Charter about advisory groups (Charter) notes that the SRC is expected to take a strategic view,<sup>2</sup> looking both forward and backward,<sup>3</sup> but is to avoid duplicating the Authority's role in assessing the day-to-day performance of the electricity system and system operator.<sup>4</sup> The Charter also makes it clear that the SRC will not generally be involved in the development of the Code or market facilitation measures,<sup>5</sup> but instead is to provide independent, authoritative, strategic advice that will help the Authority achieve its strategic objectives.
14. As well as describing the SRC's function, the Charter includes some specific activities that the SRC is expected to undertake:
  - a) the review of the system security assessments prepared by the system operator (3.4);
  - b) the review of the system operator's performance against its security of supply functions (3.4);
  - c) the receipt of six-monthly reports on the performance of the electricity system and system operator (3.7); and
  - d) consideration of the system operator's medium- to longer-term forecasting of security of supply no more than once every six months (3.7).

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<sup>2</sup> At 3.1.

<sup>3</sup> At 3.4 – 3.5, noting in particular that in respect to reliability of supply issues the emphasis is on looking forward 1 – 10 years.

<sup>4</sup> At 3.6.

<sup>5</sup> Clause 3.2 of the Charter notes that the Act does not provide for the SRC to have Code-making capability but notes at 4.3 that the Authority may from time-to-time seek the SRC's advice on Code amendment proposals.

15. The terms of reference expand on the expected activities of the SRC, identifying that as part of fulfilling the SRC's function the Authority may seek the SRC's advice on the following:
- the system operator's performance including against its principal performance obligations, security of supply function and any other function of the system operator important to the performance of the electricity system and/or reliability of supply;
  - system operation issues and/or security of supply issues identified by the Authority or brought to the Authority's attention;
  - industry development needs and priorities relating to the system operations (for input into the Authority's industry development work plan and the joint development programme to be agreed by the Authority and the system operator);
  - system security assessments and security of supply forecasts prepared by the system operator; and
  - any other matters that the Authority considers to be within the function of the SRC as set out in the Act

# System Operator Operational and System Performance Dashboard

**Prepared by:** Fraser Clark  
General Manager Operations Development

## Discussion and approval

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11 August 2011

### Requested actions

1. The Council is requested to:
  - (a) Confirm that all of the necessary performance indicators are included.
  - (b) Confirm that the information provided (both graphically and in the supporting texts) is sufficient.
  - (c) Identify whether the information presented identifies any trends or issues where they would like to provide advice to the Authority or that they consider the Authority should investigate further.

### Context

2. The dashboard that has been provided by the System Operator summarises the key system performance indicators. The preparation of such a dashboard was an action point from the first meeting.
3. The 'dashboard' of electricity system performance provided for the August 2011 meeting is expected to be prepared for each meeting of the SRC, and so achieve the requirement on the SRC to receive and consider reports on system performance.



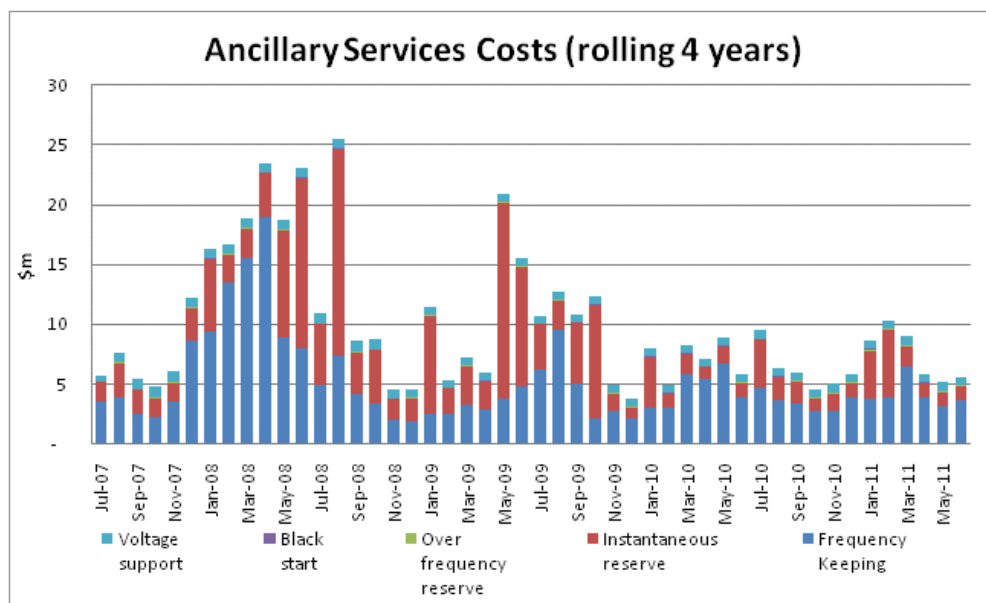
## Security and Reliability Council

### System Operator Operational and System Performance Dashboard (August 2011)

#### Introduction

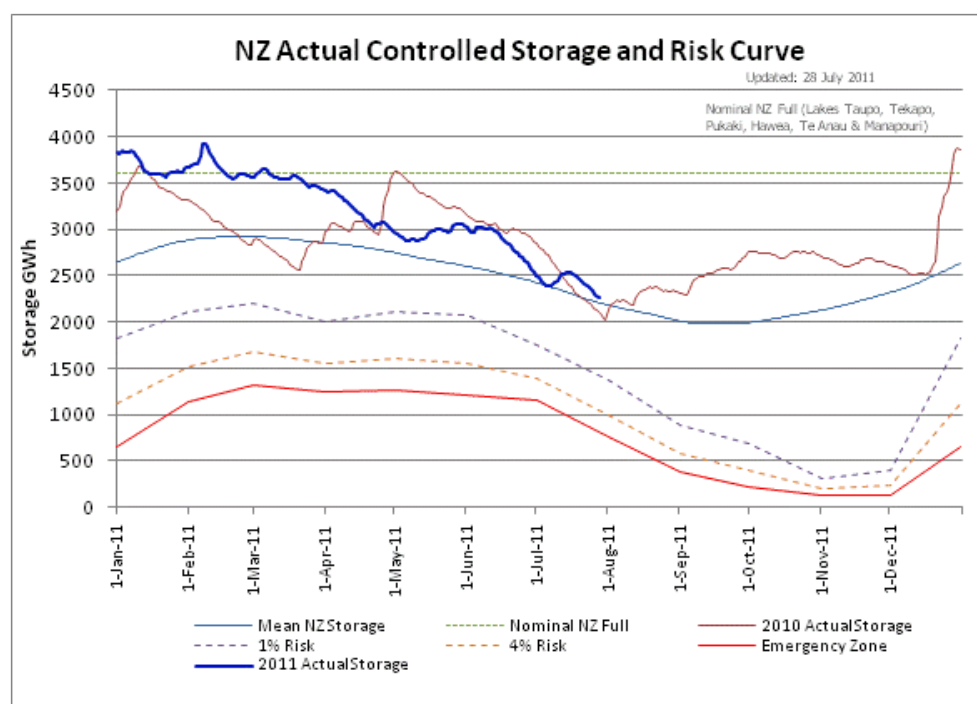
This dashboard summarises a collection of information of different reports prepared by the System Operator.

#### Ancillary Service Costs



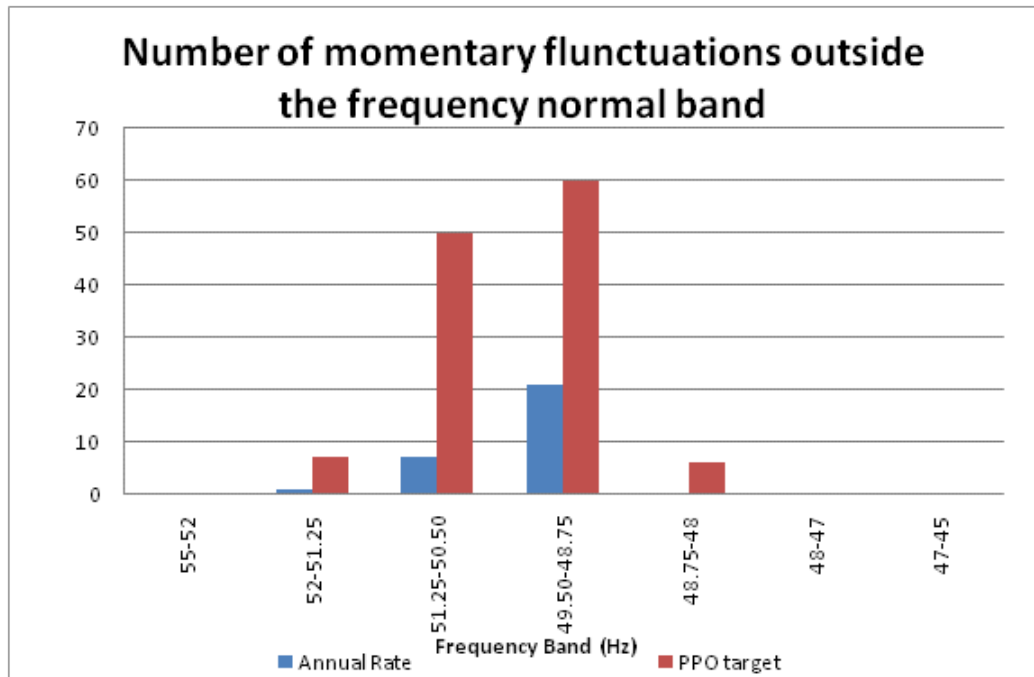
#### New Zealand Hydro Storage and Hydro Risk Curves

Security is normal, indicating there is no reason to expect electricity shortages in the medium term.

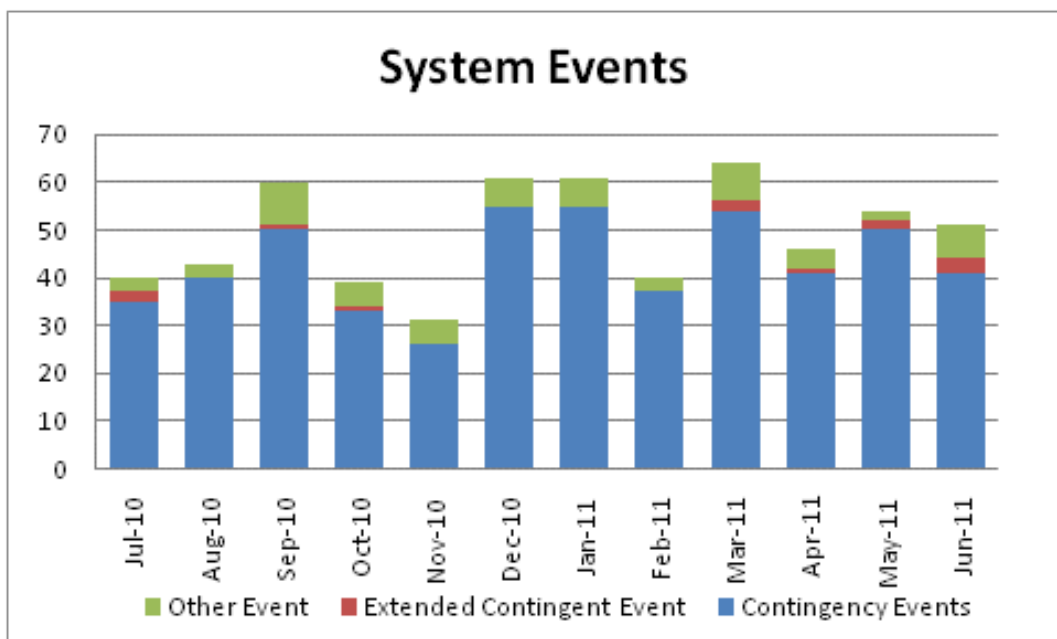


## Frequency Management

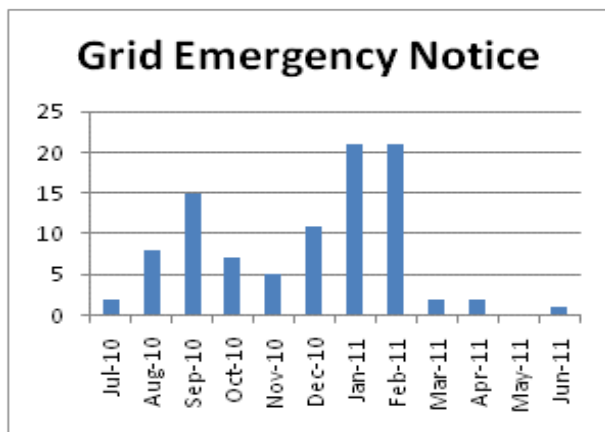
The graph below shows the total number of momentary fluctuations outside the frequency normal band, recorded in both Islands, over the last 12 months.



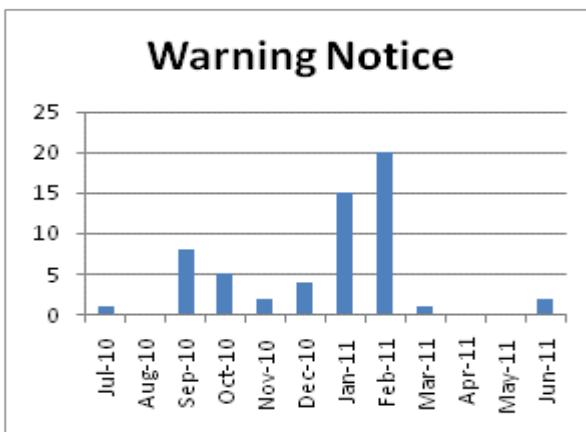
## System Events



## Grid Emergency Notice

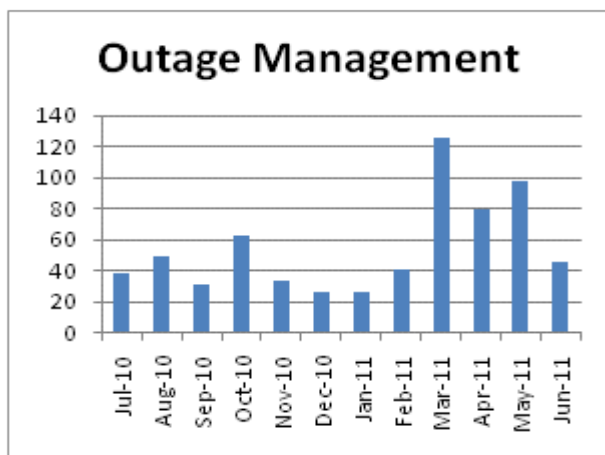


## Warning Notice



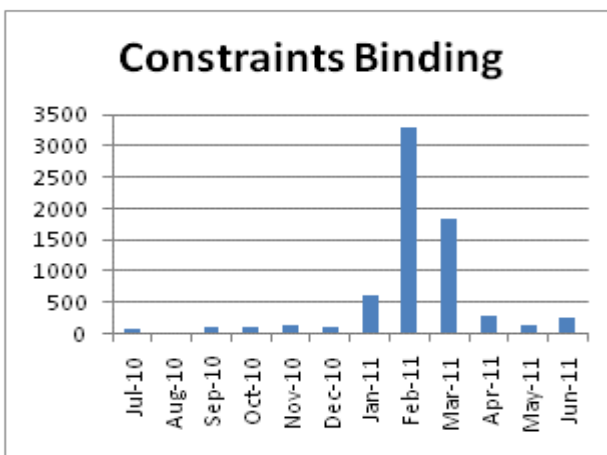
Grid Emergencies and Warning Notices were declared in Jan and Feb 2011 for insufficient generation offers in the Upper North Island and insufficient transmission capacity in the Waikato region.

## Outage Management



A high level of outages processed between Mar and May 2011 were largely due to the normal outage management life cycle. The February Christchurch earth quake also shifted some outages to March.

## Constraints Binding



High inflows in Jan and Feb 2011 caused HVDC and constraints in Hamilton and Otago regions binding.

# Security policy and standards

**Prepared by:** Fraser Clark  
**General Manager Operations Development**

## Discussion and approval

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11 August 2011

### Requested actions

1. The Council is requested to:
  - (a) note the presentations by the Authority and System Operator;
  - (b) consider if there are any 'gaps' or risks that might fall between the probabilistic and deterministic approaches that are currently applied;
  - (c) confirm that the existing winter and energy margins are considered to be sufficient, or whether they should be updated to reflect factors such as Pole 3, new generation investments and possible changes to the use of existing generation; and
  - (d) consider the relative priority of the possible review of the GRS and the development of a summer capacity margin..

### Context

2. Action points from the first meeting included an agenda item for this meeting that would see:
  - the Authority provide the historical background to the grid reliability standards under Part 12 of the Code; and
  - the System Operator describe its operational security policy and identify expected future issues that may result from the differences between the planning and operational policies.
3. As part of completing this 'picture' of the current security standards the Authority is also providing a presentation on the background to the current winter energy and capacity margins.

# Grid Reliability Standards

**Presentation to the Security and Reliability Council**

**Bruce Smith**



# Agenda

- Deterministic and probabilistic planning standards and how they are applied in New Zealand
  - see handout summarising differences between deterministic and probabilistic standards
  - see handout with Schedule 12.2 – Grid Reliability Standards contained in the Electricity Industry Participation Code (Code)
- Establishing GRS in the Code
- Process going forward



# Deterministic and probabilistic planning standards

- Development of most transmission grids have been determined by applying deterministic standards
- Deterministic standards are based on levels of network redundancy around key assets where a failure of an asset or assets (a contingent event) does not result in a loss of supply
- Deterministic standards are expressed as N-k where k is number of contingent events that a network can manage without loss of supply
- N-1 deterministic standard is applied to the Core Grid covering the loss of a single transmission circuit, a single generator, an HVDC pole, a single bus section, an interconnecting transformer, or a single shunt capacitor
- Core Grid is defined in the Code as a list of transmission assets but generally applying to any transmission assets servicing over 150MW of load



# Establishing GRS in the Code

- The GRS came into force on 13 May 2005
- GRS were established after consultation by the Electricity Commission (Commission)
  - It initially pursued an economic approach to grid reliability, strongly linking the GRS with the application of the grid investment test (GIT)
  - It acknowledged stakeholders' concerns about about the uncertainties and implementation issues associated with moving to such an approach.
  - It developed a two-limb grid reliability standard, consisting of an economic standard for the whole grid, underpinned by a “safety net” of an N-1 standard for contingencies on the core grid.



## Establishing GRS in the Code (cont'd)

- Therefore, a mixture of deterministic and probabilistic standards has been adopted
- Reviewed by Goran Strbac and Predrag Djapic (Imperial College) in 2008 -

*“Risk with the deterministic and probabilistic planning approaches In the context of balancing risk and network costs, deterministic standards will always produce a non-optimal solution, i.e. the network will be under or over-invested, depending on particular circumstances. A deterministic standard is likely to lead to over investment, and deliver an increased reliability performance above the optimum in cases of supplying relatively small demand that is located away from generation (with significant network cost). On the other hand, a deterministic standard is likely to lead to underinvestment, and hence lead to an increased level of risk and reduced reliability in cases of relatively larger demand that is located relatively close to generation (modest network costs).*

*It is however important to stress that probabilistic standards provide an opportunity for a range of non-traditional reliability enhancements to be consider and conceptually this should in the long term, lead to an improved network reliability profile.”*



# Consistency of GRS with operational standards and policies

- It was recognised when developing the GRS that:
  - The frequency, depth and duration of outages on the grid are affected by the how the system is operated in real time
  - The EGRs placed obligations (as the Code still does) on the Commission to have regard to the desirability of Parts C (7 & 8) and Part F (12) operating in an integrated and consistent manner
  - Operational standards and policies are an important aspect of considering GRS
  - If there is a dislocation between planning standards and operational standards, either the planner delivers the operator with an overbuilt grid, or the operator sheds more demand than the planner factored into their economic analysis.



# GRS in the Code

- Set out in Schedule 12.2 of the Code
- Change process for the GRS and Core Grid set out in clauses 12.66 to 12.69 of the Code
- Link between investment approval and GRS is set out in the Code. The grid satisfies the GRS if:
  - the power system is reasonably expected to achieve a level of reliability at or above the level that would be achieved if all economic reliability investments are implemented; and
  - with all assets that are reasonably expected to be in service, the power system would remain in a satisfactory state during and following a single credible contingency event occurring on the core grid.
- Economic reliability investments (schedule 12.2) mean investments in the grid and transmission alternatives that would satisfy the economic test; and having regard to Parts 7 and 8 (including the policy statement).



# Process going forward

- On the Authority's work plan to review the GRS
- Reconsideration will encompass:
  - A review of the deterministic 'limb' and core grid definition
  - Consistency with:
    - the Commerce Commission proposals for its investment test in accordance with 54S of the Commerce Act (Transpower's capex input methodology )
    - System Operator's operational standards



# Handouts for SRC Meeting 18 August 2011 – discussion on GRS

# Deterministic versus probabilistic standards within the GRS

## Deterministic standards

Until relatively recently, the development of transmission networks in most jurisdictions has largely been undertaken in accordance with deterministic GRS. For example, “deterministic” standards are often based on levels of network redundancy such as providing for continued supply under a “k” contingency criterion (often referred to as N-k). For instance:

- *(N) criterion* denotes that the transmission system is planned such that, with all transmission facilities in service, the system is in a satisfactory state and loads may have to be shed to return to a satisfactory state for a credible contingent event;<sup>1</sup> and
- *(N-‘k’) criterion* denotes that the transmission system is planned such that, with all transmission facilities in service, the system is in a secure state and for any ‘k’ credible contingency event(s) the system moves to a satisfactory state. If any further contingency events were to occur, loads may have to be shed to return to a satisfactory state.

The N-1 deterministic standard is applied to the core grid,<sup>2</sup> typically covering the loss of a single transmission circuit, a single generator, an HVDC pole, a single bus section, an interconnecting transformer, or a single shunt capacitor. These are defined as “contingent events”. If the system cannot survive the “single credible contingency” this is a signal that grid investment (or an alternative) is required to restore the required standard.

## Probabilistic standards

The alternative to this approach is a “probabilistic” reliability standard. This is applied in the non-core parts of the grid. Probabilistic reliability standards encompass the possibility of load shedding after a contingent event, and therefore attempt to take into account the probability of contingencies and the likely cost consequence of those contingencies. This requires setting a VoEUE and estimating the quantum of expected unserved energy that might arise from each contingent event, then incorporating this in the cost-benefit analysis undertaken when considering transmission/transmission alternatives investments (i.e. currently the GIT, but soon to be replaced by an input methodology developed by the Commerce Commission).

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<sup>1</sup> An N security policy results in a system that is not secure against contingent events.

<sup>2</sup> Defined in the Code as a list of transmission assets but generally applying to any transmission assets servicing over 150MW of load.

A summary of the advantages and disadvantages of the two types of reliability standards is shown in the table below.

**Table 1: Summary of possible advantages and disadvantages of a probabilistic approach**

| Potential advantages of the probabilistic approach                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                        | Potential disadvantages of the probabilistic approach                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                                         |
|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|
| <ul style="list-style-type: none"> <li>• It enables a single economic approach to be adopted for all transmission investments and a consistent evaluation of reliability benefits provided by transmission alternatives</li> <li>• It has the potential to enable improved network utilisation (but through acceptance of the risk of the possibility of load shedding for credible contingency events)</li> <li>• It avoids subjective adjustments to deterministic standards, as all reliability investment decisions for all circumstances are able to be analysed using a single modelling approach</li> <li>• It enables users' valuation of unserved energy (including different users' valuation of unserved energy in different parts of the grid) to be explicitly taken into account</li> <li>• It reduces the potential for Transpower to shift investments between investment categories (i.e. between transmission and transmission alternatives)</li> </ul> | <ul style="list-style-type: none"> <li>• Its application requires a large database on performance of the grid and its components, and on the value of unserved energy for different classes of electricity consumers</li> <li>• It leads to increased analysis costs, given the need to establish and evaluate the various probabilistic scenarios</li> <li>• There is a perception that the process is a "black box" and is more difficult to validate (whereas deterministic standards are intuitively easier to understand)</li> <li>• There is a perception that the possibility of load shedding for credible contingency events may be unacceptable (although there may be situations where the probability of loss of load from utilising N-1 may be higher than would be acceptable if modelled on a probabilistic case, for example, long radial load with high forced outage rate lines)</li> </ul> |

Source: *Consultation paper on Draft Transport Rules, ECEU, MED, 4 November 2003*

# Schedule 12.2 of the Electricity Industry Participation Code

## Grid reliability standards

### 1 Preamble

Clause 12.55 of this Code, requires the **Authority** to determine the most appropriate **grid reliability standards** and in so doing must have regard to the purposes in clause 12.56 and the principles set out in clause 12.57, as required by clause 12.55.

Compare: Electricity Governance Rules 2003 clause 2 schedule F3 part F

### 2 The grid reliability standards

- (1) The purpose of the **grid reliability standards** is to provide a basis for **Transpower** and other parties to appraise opportunities for transmission investments and **transmission alternatives**.
- (2) For the purpose of subclause (1), the **grid** satisfies the **grid reliability standards** if—
  - (a) the power system is reasonably expected to achieve a level of reliability at or above the level that would be achieved if all **economic reliability investments** were to be implemented; and
  - (b) with all **assets** that are reasonably expected to be in service, the power system would remain in a **satisfactory state** during and following a **single credible contingency event** occurring on the **core grid**.
- (3) For the purpose of subclause (2)(a), the expected level of reliability of the power system must be assessed at each and every **grid exit point** and **grid injection point** (wherever located on the **grid**).
- (4) For the purpose of subclause (2)(a) and (b), the expected level of reliability, and state, of the power system must be assessed using the range of relevant operating conditions that could reasonably be expected to occur.

Compare: Electricity Governance Rules 2003 clauses 3 to 6 schedule F3 part F

### 3 Interpretation and definitions

- (1) For the purposes of these **grid reliability standards**, unless the context calls for another interpretation—
  - (a) the terms defined in Part 1 of this Code take that defined meaning; and
  - (b) the term defined in subclause (2) takes that defined meaning; and
  - (c) a reference—
    - (i) to the singular includes the plural and conversely; and
    - (ii) to a person includes an individual, company, other body corporate, association, partnership, firm, joint venture, trust, or Government Agency; and
  - (d) the word including or includes means including, but not limited to, or includes, without limitation; and

- (e) *the other grammatical forms of the term defined in subclause (2) have a corresponding meaning.*
- (2) **Economic reliability investments** means investments in the **grid** and **transmission alternatives** that would satisfy the economic test for an investment proposal applied by the Commerce Commission under Part 4 of the Commerce Act 1986—
  - (a) *assuming that the economic test was applied to both investments in the **grid** and **transmission alternatives**; and*
  - (b) *having regard to Parts 7 and 8 (including the **policy statement**).*

*Compare: Electricity Governance Rules 2003 clauses 7 and 8 schedule F3 part F*

#### **4 Value of expected unserved energy**

- (1) *The value of **expected unserved energy** is—*
  - (a) *\$20,000 per **MWh**; or*
  - (b) *such other value as the **Authority** may determine.*
- (2) *The **Authority** may determine different values of **expected unserved energy** for different purposes and for different times.*
- (3) *If the **Authority** determines a value of **expected unserved energy** under this clause, the **Authority** must **publish** its determination.*





# SRC – System Operation and Grid Planning Standards

August 2011

System Operator  
10/08/2011



SYSTEM OPERATOR

*Keeping the energy flowing*

TRANSPower



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## 1 Introduction and purpose

All transmissions systems are planned and operated to be robust to certain types of events occurring on the system, especially those that are more likely to occur and could have a significant impact on reliability. Equally, they are not operated to be robust to very unlikely events, where the cost of such mitigation would be prohibitive.

System operating and grid planning standards have different purposes. System operation standards are about managing supply of electricity risks with the assets made available at a particular time. Grid planning standards are concerned with what assets should be built to provide a range of benefits to parties generating or consuming electricity.

This note summarises system operation and grid planning standards and their regulatory framework in New Zealand.

## 2 System operation standards

The principal performance obligations of the system operator, under Part 7 of the Electricity Industry Participation Code (the Code), require it to act as a reasonable and prudent system operator in:

- Dispatching assets made available in a manner that avoids cascade failure resulting in the loss of demand arising from frequency or voltage excursions or supply and demand imbalances
- Maintaining frequency and frequency time error within defined bands, and restoring it if necessary

The system operator identifies credible events that may result in cascade failure, due to these events causing assets to exceed stated capability or voltages to go outside the ranges defined in Part 9 of the Code.

The system operator publishes a policy statement that sets out policies and means that the system operator will use to meet the principal performance obligations. The policy statement is incorporated by reference in the Code following a prescribed industry consultation and Authority approval process. The system operator may depart from the policy statement when a system security situation arises and such departure is required in terms of the system operator acting as a reasonable and prudent system operator.

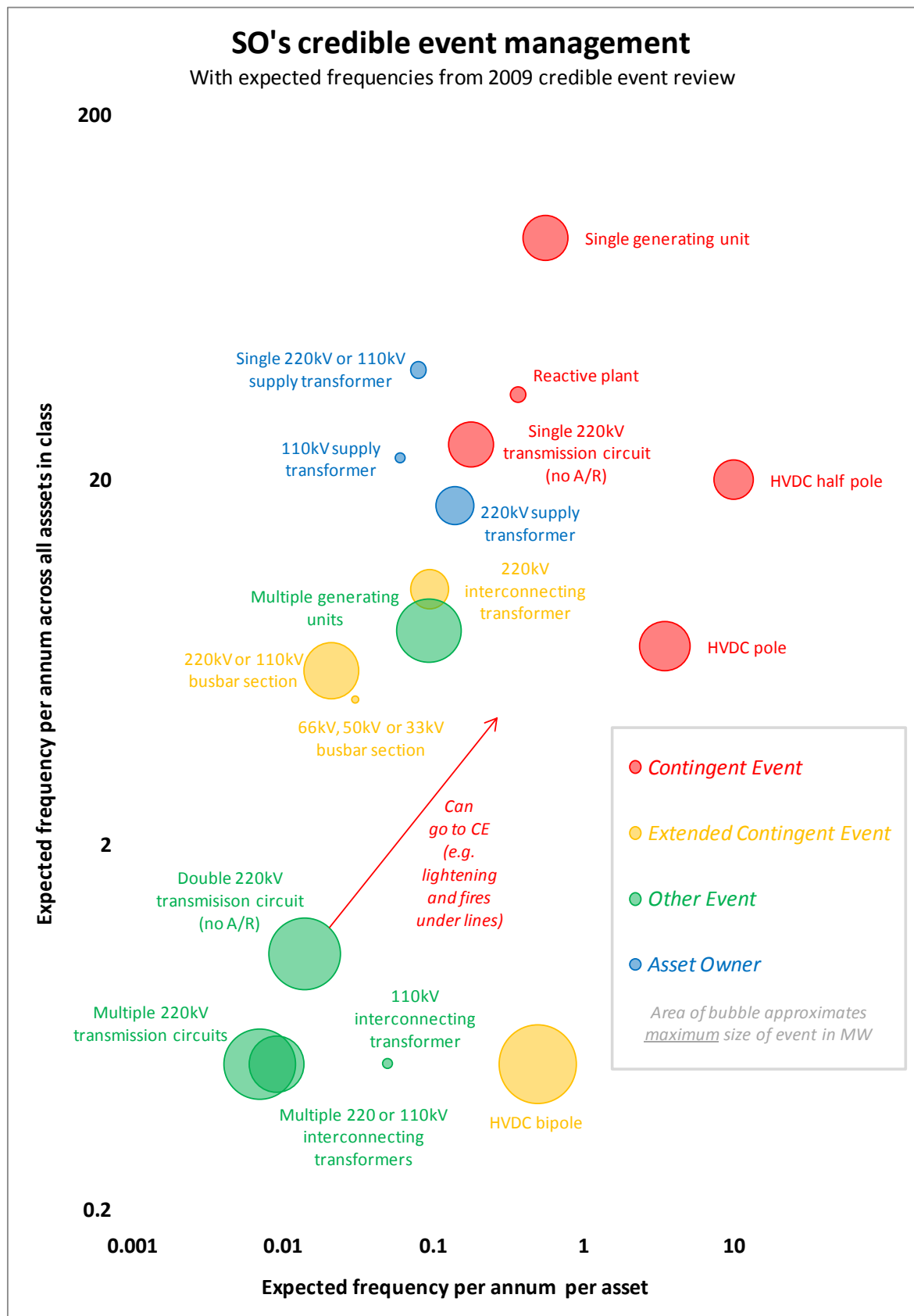
The system operator reviews the identification, assessment and assignment of potential credible events at least every five years. The most recent review was concluded in 2009. The review identifies possible events and, according to their likelihood and physical and economic consequence, divides them into four categories of how they will be managed. The current categories are tabulated overleaf.

| Category                   | Description                                                                                                                                                                                                                                                                                                                                         | Operational implication                                                                                                          |
|----------------------------|-----------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|----------------------------------------------------------------------------------------------------------------------------------|
| Contingent events          | Events where the impact, probability of occurrence and estimated cost and benefits of mitigation are considered to justify implementing policies that are intended to be incorporated into the scheduling and dispatch processes pre-event.                                                                                                         | <i>The system is operated such that if these events occur there will be no loss of load</i>                                      |
| Extended contingent events | Events for which the impact, probability, cost and benefits are not considered to justify the controls required to totally avoid demand shedding and maintain the quality limits defined for contingent events.                                                                                                                                     | <i>The system is operated such that if these events occur there may be automated load shedding, such as AUFLS or inter-trips</i> |
| Stability events           | Severe power system faults that might lead to a defined contingent event, extended contingent event or loss of an interconnecting transformer or busbar section. For these faults it is deemed prudent to ensure that the transient and dynamic stability of the power system is maintained.                                                        | <i>Currently there are no events assigned as stability events.</i>                                                               |
| Other events               | Events which are considered to be uncommon and for which the impact, probability of occurrence and estimated cost and benefits do not justify implementing available controls, or for which no feasible controls exist or have been identified, other than unplanned demand shedding, AUFLS and other emergency procedures or restoration measures. | <i>The system is operated such that if these events occur there may be uncontrolled loss of load.</i>                            |

In addition, supply transformer events are managed by the relevant asset owner.

An important consideration is that the system operator manages events with the assets made available at the time. At some times there may be insufficient assets made available to provide a secure grid.

The following diagram illustrates the current categorisation of credible events.



### 3 Grid planning standards

The grid owner invests in assets that provide benefits to connected parties and end consumers. The grid owner's investment plans are overseen by the Commerce Commission. The Commerce Act (Transpower Input Methodologies) (Capital Expenditure) Determination 2011 is expected to be finalised soon, to replace Part F of the old Electricity Governance Rules (EGRs) as the framework for approving grid investment. It will (assuming its current form) require investments to have:

- Highest positive expected net electricity market benefit (the 'economic limb'), or
- Highest expected net electricity market benefit and meet the deterministic limb of the grid reliability standards, under Schedule 12.2 of the Code.

In this way, the Commerce Commission's approval process references the grid reliability standards in the Code.

The economic limb allows for investments in grid assets where there is a positive expected net market benefit. This benefit may arise from reliability considerations (e.g. avoiding energy not served) or through other considerations such as a reduction in system losses or relief of generation constraints.

The deterministic limb of the grid reliability standards requires that, with all assets that are reasonably expected to be in service, the power system would remain in a satisfactory state during and following a single credible contingency event occurring on the core grid. Thus, it is an N-1 standard, excepting that some allowance may be made for conditions when assets (both transmission and generation) are out of service. The consequences of an N-1 event occurring when assets are out of service should be accounted for on a probabilistic basis and hence proved economically.

Single credible contingency events are defined in Part 1 of the Code as comprising any of the following:

- a single transmission circuit interruption
- the failure or removal from operational service of a single generating unit
- an HVDC link single pole interruption
- the failure or removal from service of a single bus section
- a single inter-connecting transformer interruption
- the failure or removal from service of a single shunt connected reactive component

The determinist limb applies only to the core grid, which is defined in Schedule 12.3 of the Code as those assets that comprise the transmission links explicitly listed in that schedule. The Code provides a formal process for reviewing the core grid definition.

Events on the non-core grid, or other or multiple events on the core grid, are included where covering them has positive expected net electricity market benefit, i.e. under the 'economic limb'. They are therefore analysed separately for each grid upgrade plan or GUP, soon to be replaced by the major capital proposal or MCP.

Planning of the grid must take a number of considerations into account including operational standards. Planning considers the need for windows in which assets can be taken out of service for planned maintenance. Grid upgrades consider the need to take assets out of service to carry out upgrades in terms of timing of the upgrade or the mitigation measures required during the outage to avoid managing load.

It is accepted that there will be times when demand or generation will not have N-1 security (e.g. during planned maintenance outages). This is because it is not economic to provide additional assets to provide that security for a small number of days each year.

Planning of the grid also takes into consideration environmental and property considerations (such as existing and future transmission corridors) and the amount of resources available to design, build, commission and maintain grid assets.

Planning of the grid considers mitigations and restorative measures for major failures. For example, the installation of auto-synchronism points on the grid will enable faster restoration of supply following events which cause the power system to split into separate islands.

## 4 Consistency

System operating and grid planning standards serve different purposes and so are not identical, but do need to be consistent.

Both system operating and grid planning standards are defined by the regulatory framework of the Commerce Act and the Code.

The interdependency between system operating and grid planning standards is recognised in the Code, which requires that with respect to the grid reliability standards and core grid definition, the Authority must have regard to the desirability of Parts 7 (system operator) and 8 (common quality) and Part 12 (transport) operating in an integrated and consistent manner.

# Energy and the Winter Capacity Margins

**Presentation to the Security and Reliability Council**

**Peter Smith**



# Agenda

- Background
- Winter Energy Margin
- Winter Capacity Margin
- Next Steps



## Background

- The Electricity Act 1992 and Government Policy Statement required the Electricity Commission (Commission) to develop energy and capacity adequacy standards (margins)
- Expected material breaches of these standards were intended to be triggers for interventions by the Commission to procure reserve energy and capacity
  - The Commission will procure Reserve Energy if the Winter Energy Margin is forecast to fall below 17% for New Zealand as a whole, or below 30% for the South Island, over the next 3 years
  - The Commission will procure Reserve Capacity if the Winter Capacity Margin is forecast to fall below 780 MW over the next 2 years
  - Procurement will balance the costs, benefits and risks of Reserve Energy/Capacity and focus on options which maximise overall welfare



## Background

- The Electricity Industry Act 2010:
  - transferred the responsibility to System Operator to provide information of security of supply for short and medium term which apply the margins in the assessing security of supply
  - Required that the Electricity Industry Participation Code (Code) specified the functions of the System Operator
  - The Authority remains responsible for setting the margins
  - No requirement on any entity to procure reserve energy or capacity
- Sale of Whirinaki



# Background

- Part 7 of the Code set out the System Operator's:
  - Performance obligations with respect to common quality and dispatch
  - Functions in relation to security of supply and supply emergencies
  - Performance review conditions



## Functions in relation to security of supply

- Part 7.3 sets out the functions of the System Operator in respect of providing information on security of supply –
  - Publish at least annually a 5 yr+ security of supply assessment (ASA) which assist parties assess whether the ‘security of supply standards’ (margins) are likely to be met
  - Consult with those parties prior to the publishing the ASA
  - There are two energy security of supply standards:
    - Winter energy margin of 17% for New Zealand
    - Winter energy margin of 30% for the South Island
  - There is one capacity security of supply standard:
    - Winter energy margin of 780MW for the North Island



# Standard for energy adequacy - Winter Energy Margin

- Published in 2008 - Winter energy margin of 17% for New Zealand and winter energy margin of 30% for the South Island. The difference between the expected amount of energy that can be supplied during the winter and expected demand during the winter, expressed as a percentage of expected demand
- Expected Supply/Expected Demand – 1 (ES/ED -1)
- Expected Supply (ES) will be determined by the following formula (all units in GWh):
  - $ES = T + W + B + H$
  - T = Maximum expected thermal generation available to meet winter (1 April to 30 September) energy demand allowing for forced and scheduled outages, available fuel supply and transmission constraints
  - W = Expected winter (1 April to 30 September) wind generation based on long-run average supply
  - B = Expected winter (1 April to 30 September) generation available from geothermal and cogeneration plants based on long-run average supply
  - H = Expected winter (1 April to 30 September) hydro generation based on mean inflows and including expected 1 April start storage of 2750 (2400) GWh for New Zealand (South Island).
- Expected Demand (ED) will be determined by forecasting the demand for electricity generation during the period 1 April to 30 September, allowing for demand response to electricity prices



# Standard for capacity adequacy - Winter Capacity Margin

- Published late 2008 - expressed as a minimum 780MW margin of de-rated North Island supply over the average of the highest 200 half hour of winter North Island daytime demands
- North Island supply includes the contribution of supply from the South Island
- The Winter Capacity Margin will be determined by subtracting a measure of North Island expected demand from North Island expected capacity.
- Basis for 780MW
  - Economic standard – balance between the cost of reserve capacity (back-up peaking) against the cost of shortfall - rejected applying international norms or assessments based on good practice
  - Load Duration Curve (LDC) convolution approach - captures the interaction between supply and demand on a probabilistic basis



## Next steps

- Further consideration of:
  - Summer capacity margin
  - Update winter energy and capacity margins given changes since they were set:
    - Pole 3
    - New generation
    - Decisions about existing generation



# Security and reliability across the industry

**Prepared by:** Fraser Clark  
General Manager Operations Development

## Discussion

---

11 August 2011

### Requested actions

1. The Council is requested to:
  - (a) Discuss risk management across the industry including a specific discussion reflecting on the system security and reliability impacts of the assets managed by generators and lines companies. The ultimate objective of this item could be a report prepared for the SRC by the secretariat identifying for consumers how the electricity system as a whole provides for and manages the risks to system security and reliability.

### Context

2. At the first meeting it was agreed that the agenda for this meeting would include a look at how security and reliability is influenced by generation and distribution companies (and not just the System Operator and Grid Owner). What risk management systems do these companies have in place to ensure secure and reliable operation?
3. It was intended that the relevant SRC members outline their risk management systems at this meeting. However, given the broad scope of the issue and the nature of some of the material this agenda item will consist of a general discussion rather than formal presentations.

# Under-frequency management

**Prepared by:** Fraser Clark  
**General Manager Operations Development**

## Information

---

11 August 2011

### Requested actions

1. The Council is requested to:
  - (a) to note that these Common Quality work streams are ongoing and will ultimately require Code changes and implementation by the System Operator and the industry.

### Context

2. The paper summarises some of the Common Quality work streams that are currently being undertaken by the System Operator as part of the work programme agreed with the Authority. The System Operator has recently published reports on these issues and has undertaken a series of workshops in Auckland, Wellington and Christchurch. The Authority makes the following comments regarding this paper:

#### *Automatic Under-frequency Load Shedding (AUFLS)*

3. AUFLS in the North Island has been found to have block discrimination issues. This has led to the recommendation of a move from the current 2 x 16% blocks to 4 x 8% blocks that require new df/dt (rate of change of frequency) relays.
4. In the South Island the issue is not with the speed of operation but with having a sufficient quantity of AUFLS available. The Tiwai grid exit point is currently not incorporated into the AUFLS system.

#### *Reserve Review*

5. A review of actual under-frequency events has indicated that in the majority of these events the frequency does not fall below 49Hz, while the Code allows for a target frequency of 48Hz in these circumstances. This indicates that there may be significant over-procurement of reserves.

6. The System Operator has identified several modelling tool changes and potential for new reserve products which could provide performance benefits and reduce total system costs.
7. The System Operator is continuing to engage with the Authority and the industry with a view to establishing a set of recommended actions.

*Normal Frequency Review*

8. 'Normal frequency' relates to systems and processes that maintain the system within its target operating band of  $50 \pm 0.2$  Hz.
9. The System Operator has:
  - Confirmed that the current normal frequency band is optimal for New Zealand;
  - Confirmed that the existing frequency keeping procurement band of  $\pm 50$  MW is required for the North Island;
  - Recommended a trial to reduce the South Island frequency keeping procurement band to  $\pm 10$  MW at certain times;
  - Recommended a trial removal of the time error requirement; and
  - Suggested code changes to clarify generator governor performance.

# SRC – Under frequency management

August 2011

System Operator  
10/08/2011



*Keeping the lights on  
24 hours a day, 7 days a week*

SYSTEM OPERATOR

*Keeping the energy flowing*

TRANSPOWER



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| <b>3</b> | <b>CONCLUSIONS .....</b>                               | <b>6</b> |

## 1 Introduction and purpose

This paper summarises the recent Common Quality work streams completed by the System Operator. In August 2011, the System Operator has published:

- (i) Stage II of the Automatic Under Frequency Load Shedding (AUFLS) review; a follow-up of the technical work completed in late 2010 on the effectiveness of the current AUFLS arrangements
- (ii) Reserve Review; a review of the arrangements for procuring reserves to mitigate the risk of under-frequency events on the system
- (iii) Normal frequency review; a review of the effectiveness of the current arrangements for normal frequency regulation, including the probability standard contained in the codes.

All the above work was done by the System Operator under the Technical Advisory Services Contract (TASC).

The cost of the work completed under (i) and (ii) was shared with the Electricity Authority in recognition of the System Operator's role as a reasonable and prudent System Operator under the Codes. The work streams are sub projects of the overall project work to review the effectiveness and efficiency of the current industry under-frequency arrangements.

## 2 Summary

The paragraphs below summarise the key outcomes from the work undertaken:

### 2.1 Automatic Under Frequency Load Shedding (AUFLS)

The results of the technical review completed in 2010 concluded that the overall design of the AUFLS scheme provides the System Operator with insufficient confidence that it will be effective to prevent the system from collapsing from large risks that are not currently identified. Furthermore there is concern that the current AUFLS scheme could result in over-frequency and potentially system collapse from defined risks.

To address the issues identified in the technical review, the System Operator has been working through the process of identifying technical options and undertaking cost-benefit analysis on those technical options. In addition, following a number of participants raising concerns regarding inefficiencies in the current AUFLS provision method (which can result in limiting participation in the instantaneous reserves market), the System Operator has also been investigating opportunities to improve AUFLS provision efficiency.

The System Operator has concluded that using  $df/dt$  relays results in a net benefit in the range of \$16 million to \$89 million over 15 years and the use of such relays would be appropriate as an AUFLS scheme for the North Island.

The System Operator believes it is prudent to hold off proposing new AUFLS schemes in the South Island until there is further clarity of the future of AUFLS

provision at the Tiwai grid exit point. In the interim, the System Operator has identified that increasing the trip setting of the second AUFLS block to 46 Hz will offer considerable improvement of the current South Island AUFLS scheme.

As a part of the review, the System Operator conducted a discussion of AUFLS provision options, including a dynamic procurement option, with industry at workshops held in April 2011. From the workshop discussion, there did not appear to be any widespread desire for dynamic market arrangements nor a lack of firm proposals as to how such market arrangements would ensure the provision of AUFLS load.

The continued use of a mandated AUFLS scheme will be required in the interim. The System Operator, in its report, has outlined options available within the current code that may assist with limiting the over-provision associated with a mandated AUFLS scheme and increase the efficiency of providing AUFLS load.

The technical options, and associated benefit analysis, will be presented and discussed with industry at the upcoming System Operator workshops in August 2011. Following from the workshops, the System Operator will consider industry feedback before making a recommendation to the Electricity Authority.

## 2.2 Reserve Review

The System Operator and the Electricity Authority, in line with the industry Common Quality Development Plan, agreed to review the Under-Frequency Management arrangements. The purpose of the Under-frequency review was to propose strategies and measures that offer the most reliable, secure, and cost effective under-frequency management system to provide greater certainty on system integrity during major under-frequency events, and to operate an efficient market

The review included the various assumptions used in the System Operator's Reserve Management Tool (RMT) to calculate reserve procurement quantities. The System Operator recommends the following improvements to the modelling within RMT:

- Changing the current 60s simulation in RMT to 10s
- Modelling the actual delivery times and quantities for Interruptible Load
- Using the actual HVDC transfer limit of 250MW rather than the modelled 25MW

The above changes will have an impact on participants with respect to data resolution and the likely occurrence of more severe under-frequency events. As such, industry endorsement of the changes is critical, and software, code, and procurement contract changes are likely to be necessary before the changes can be implemented.

The System Operator has also concluded that a mix of reserves is essential and beneficial for managing system disturbances. Therefore, to retain an appropriate mix of products and ensure provision of one type of reserve is not inadvertently incentivised over another, a transparent approach for all reserve providers for testing and monitoring is desirable.

Further, as the New Zealand power system changes and evolves; more changes in its generation mix are expected. It is expected that with higher HVDC transfer, the frequency will reach its minimum in less than the mandated 6s. The System Operator therefore recommends further investigation of faster reserve products such as faster operating IL, df/dt operated reserves, faster spinning reserve, and system inertia.

## 2.3 Normal Frequency Review

### 2.3.1 *Normal frequency limits and standards*

This work stream was one of the frequency related initiatives the Authority instigated as part of its strategic common quality development plan. The System Operator looked specifically at the appropriateness of the normal frequency band (currently 50 Hz  $\pm$  0.2 Hz) and the probability standard, which specifies the number of allowable excursions into the defined frequency bands under the System Operator's Principal Performance Obligations (PPO). In addition, the System Operator reviewed the appropriateness of the size of the frequency keeping MW band required of the Frequency Keeper (currently 50 MW).

The System Operator concluded that the normal frequency band is optimal for New Zealand. While widening the normal frequency band may decrease frequency keeping costs, it would increase reserve requirements, potentially resulting in a higher overall cost of electricity supply. It could also lead to security concerns. The relatively small network and comparatively few generators and consumers mean that frequency control is only possible through highly tuned controllers to maintain supply reliability<sup>1</sup>. The current normal frequency band is already wider than the band in most countries surveyed and therefore considering the unique challenges posed by the relatively small size of the New Zealand transmission system it is unreasonable to widen it further.

For the current frequency bands, the average number of deviations over the previous seven years has been less than the prescribed number for the current probability standard limits. However, it is the System Operator's view that changing the probability standards will not drive changes to system frequency management and/or System Operator operational practices to manage system frequency. The System Operator does not currently operate the power system to specifically meet a probability particular standard. A change to the probability standard is not recommended. Instead, clarification of the purpose of the standard as a PPO is strongly recommended.

However, from the analysis it was noted that deviations into the bands 49.8 to 49.5 Hz and 50.2 to 50.5 Hz have increased markedly and are still increasing. The causes of these deviations needs to be identified and understood to ensure there is no unknown power system risks or additional actions that need to be taken to mitigate the risks.

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<sup>1</sup> Graeme A. Chown, The Economic Analysis of Relaxing Frequency Control, 2007, p. 3

No discernable interdependence was found between the frequency keeping band, normal frequency band, and the probability standard

The frequency keeping trials performed in 2008 have clearly shown that a band of  $\pm 50$  MW is still required in the North Island. However, in the South Island, frequency keeping trials have shown that the band could be relaxed further during overnight hours. A new frequency keeping trial band of  $\pm 10$  MW is recommended in the South Island from 0100 to 0500.

### **2.3.2 Time Error**

The Electricity Industry Participation Code requires the error between actual time and a synchronous clock connected to the power grid to be no more than five seconds. However, the uses for which time error was originally developed have become obsolete, and there is evidence that artificially raising or lowering the frequency to correct the time error can become a system reliability issue.

Transpower recommends consulting New Zealand electricity market participants to determine whether a Code requirement for time error is still necessary. If time error is not used, Transpower recommends a six-month trial for removing the 5-second time error requirement from the Code.

### **2.3.3 Generator AOPOs within the Normal Frequency Band**

The System Operator reviewed the Asset Owner Performance Obligations relating to the responsiveness of generating units to frequency deviations within the normal band. Some of the requirements in the Code are unclear or have been misinterpreted. The System Operator has suggested Code changes to provide clear guidelines for asset owners with respect to dead band, droop, and proportional and integral gain settings.

## **3 Conclusions**

The Authority and the System Operator have put in a significant amount of effort over the last 6 months to progress the common quality initiatives on the Common Quality Work Plan. The majority of the initial studies have been completed. The recommendations arising from the review undertaken will require further works and are, in some cases, substantial changes. The System Operator and the Electricity Authority will continue to develop and progress the recommendations in the form of a prioritised implementation plan.

# Christchurch earthquake

**Prepared by:** Fraser Clark  
General Manager Operations Development

## Information

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11 August 2011

### Requested actions

1. The Council is requested to:
  - (a) note the presentations on what Orion and Transpower have learned from the Christchurch earthquake; and
  - (b) identify any industry-wide security and reliability issues that they consider that the Authority should investigate.

### Context

2. This agenda item was agreed at the first SRC meeting.
3. John O'Donnell, the GM Infrastructure from Orion will join the meeting to present the Orion perspective.

# 4 September 2010 and 22 February 2011 Christchurch Earthquakes from a Transmission Grid Infrastructure Perspective



## Asset Structural Performance and Lessons Learned

By Craig McGhie and Christophe Tudo-Bornarel

TRANSPOWER

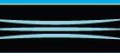
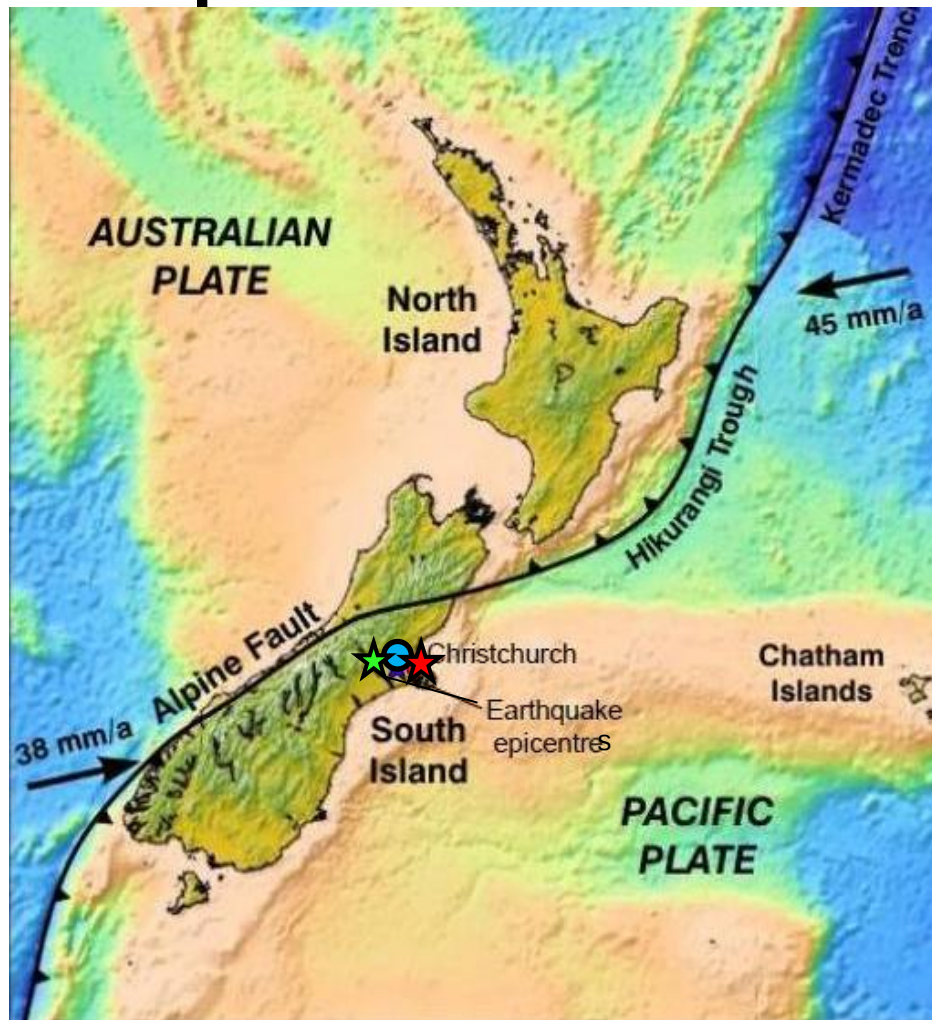


# Key Points

- Overall the transmission grid performed well.
- The transmission grid in the Canterbury region experienced considerable variation in the nature and level of seismic loading.
- Transpower experienced a small number of equipment breakages and transformer trips in both events.
- Earthquake risk identification and strengthening programmes following 1987 Edgecumbe earthquake paid dividends.
- Further/continuing work required to identify risks and built resilience into transmission grid.



# Earthquake - In Summary



# Earthquakes & Aftershocks

- ★ 4 Sep 2010 4:36am, M7.1, 10km deep, 40km West of CHC
- ★ 22 Feb 2011 12:51pm, M6.3, 5km deep, 10km SE of CHC

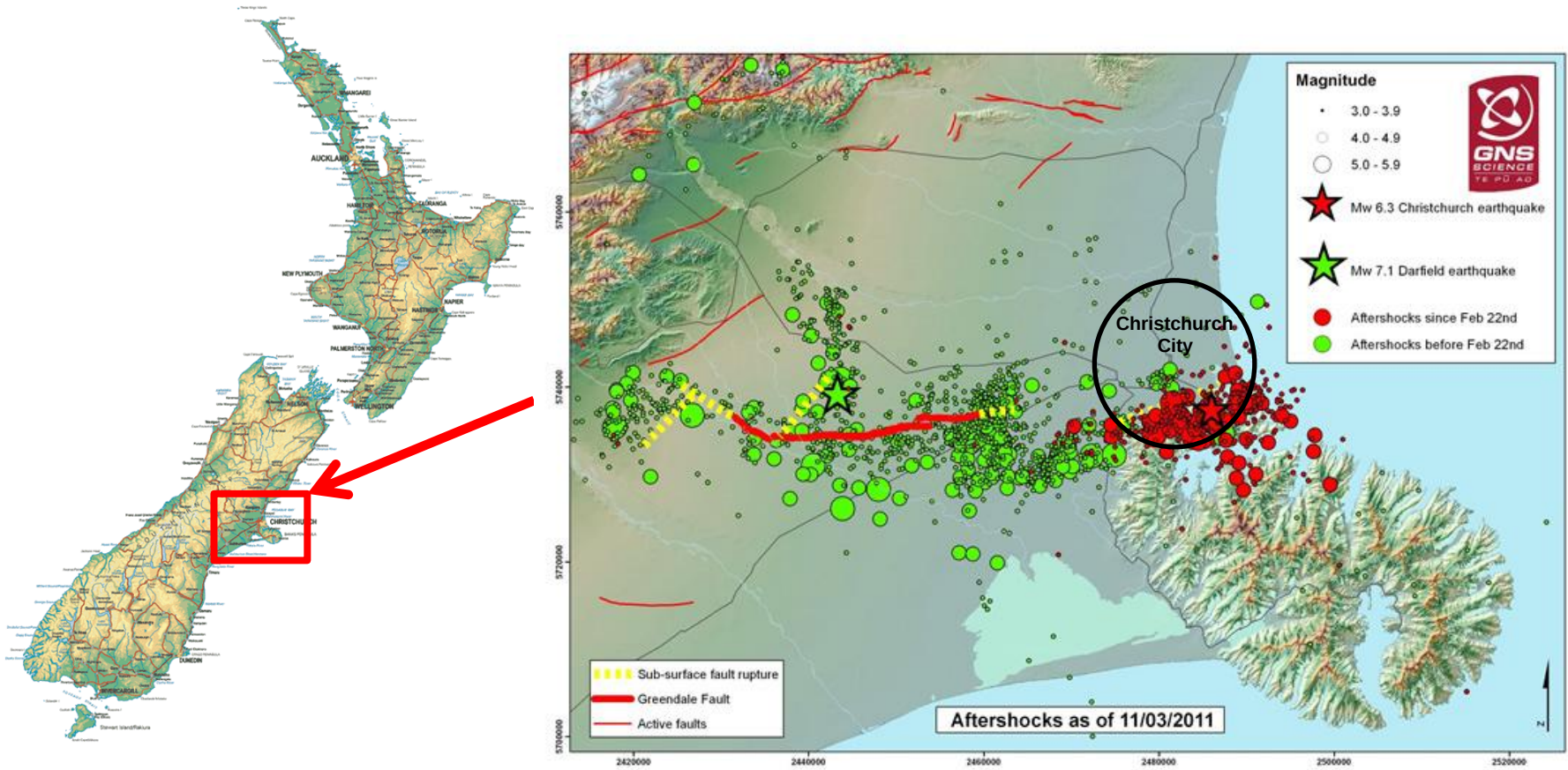


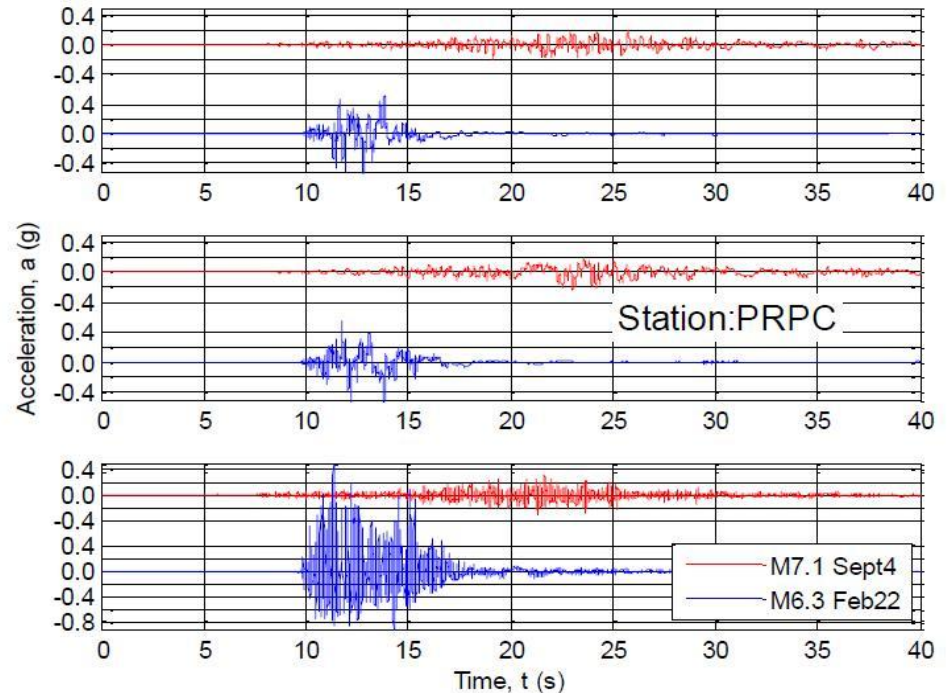
Image Courtesy of GNS

# Earthquake Accelerations

## Peak Ground Accelerations

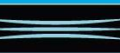
| Direction         | Darfield<br>4 Sept 2010 | Christchurch<br>22 Feb 2010 |
|-------------------|-------------------------|-----------------------------|
| Horizontal<br>PGA | 0.8g                    | 1.7g                        |
| Vertical<br>PGA   | 1.25g                   | 2.2g                        |

Ground accelerations recorded at Pages Road Pumping Station approximately 1.5km NW of Bromley Substation



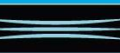
Courtesy Brendon Bradley, from NZSEE database website  
[http://db.nzsee.org.nz:8080/en/web/chch\\_2011/home](http://db.nzsee.org.nz:8080/en/web/chch_2011/home)

Data source GNS

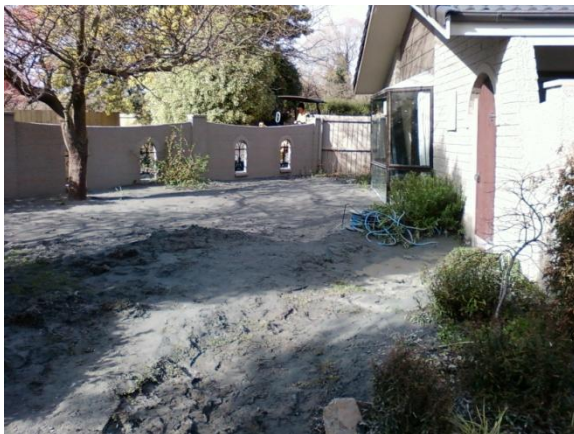


# Darfield Earthquake

- Saturday, 4 September 2010 at c. 4:36 a.m. local time
- Magnitude 7.1, 40 km West of Christchurch at a depth of 10km
- 0 fatalities, only 2 serious injuries
- Surface rupture of c. 29 km, with strike-slip displacements of up to 4m.
- Shaking damage
  - predominantly confined to pre-1930's brick and un-reinforced masonry structures.
- Liquefaction, lateral spreading and surface rupture damage
  - Significant damage to residential buildings, lifeline infrastructure (power, water, wastewater), and roads.
- Cost: Estimate of \$4 billion

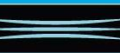


# Darfield Earthquake



# Christchurch Earthquake

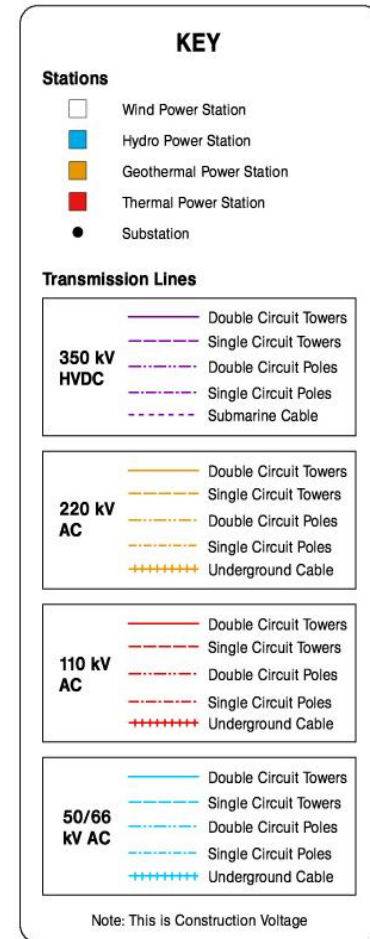
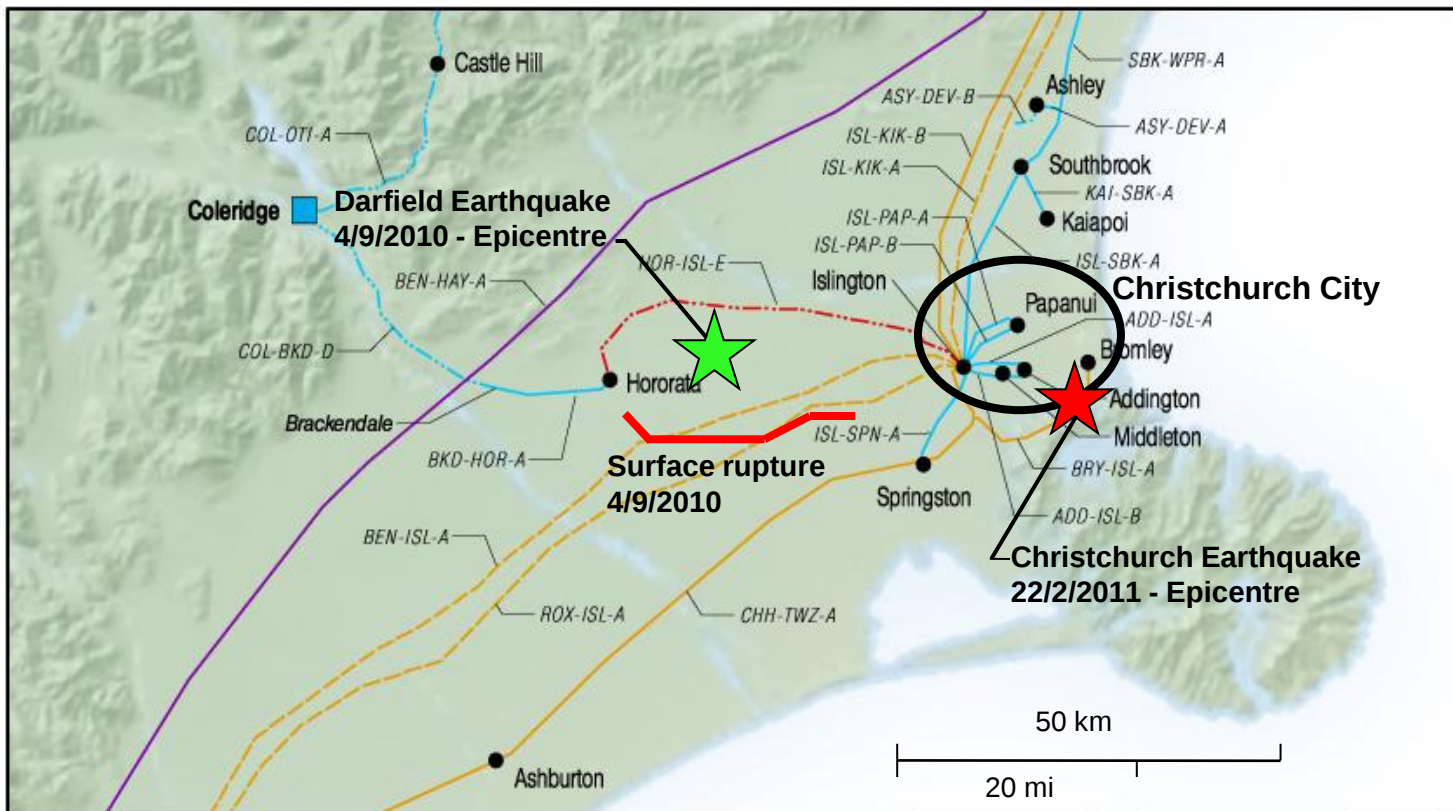
- Tuesday, 22 February 2011 at 12:51 p.m. local time
- Magnitude 6.3, 9 km SW of Christchurch CBD at a shallow depth of 5km
- 181 fatalities and 161 seriously injured
- Shaking damage
  - Widespread damage with collapse of many buildings.
  - Over 1000 buildings requiring demolition in the CBD
- Liquefaction, lateral spreading and surface rupture damage
  - Extensive damage to residential buildings, lifelines (power, water, wastewater), and roads.
- Slope stability and rock fall damage
  - Extensive damage residential buildings and roads.
- Cost: estimate of \$16 billion



# Christchurch Earthquake



# Transmission Network and Assets



# Earthquakes Impact

## DARFIELD EARTHQUAKE – 4 SEPTEMBER 2010

- Minor damage to Transmission infrastructure
- Loss of Service, restored 8:30 a.m. (4 hours after event) with 100% capacity and n-1 security

## CHRISTCHURCH EARTHQUAKE – 22 FEBRUARY 2011

- Minor damage to transmission infrastructure at Bromley substation
- Further minor damage at Papanui substation
- Loss of Service, restored 17:29 p.m. (4 hours:40min after event) with 100% capacity and n security at Bromley substation



# Physical Damage

## Darfield Earthquake

- Minor cracking of control buildings
- **Dislodgement of base isolated control cabinet at ROC**
- Spare 66kV CT (two damaged)
- **Fractured 220kV Surge arrestor**
- Cracked yard slabs and transformer bunds
- **ISI-PAP B 66kV line failed terminal span**
- BEN-ISL A 220kV line bent earth peak
- BEN-ISL A and ROX-ISL A insulator displacement
- Collapsed storage racks at warehouse.
- Tripping of mercury and **aseismic switches** on transformers

## Christchurch Earthquake

- Minor cracking of control buildings
- Fractured 66/11kV transformer bushing (two damaged)
- Fractured 220kV CVT
- Damaged 11kV Switchgear
- Cracked yard slabs and transformer bunds
- Collapsed storage racks at warehouse.
- Tripping of mercury and **aseismic switches** on transformers

# Physical Damage - Substations

## Darfield Earthquake



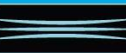
### Hororata substation

- 1940's reinforced concrete crane building sustained large shear cracks but repairable.
- Damaged spare 66kV CT



### Islington substation

- 220kV surge arrester mounted on top of radiators failed
- Control cabinet dislodged from base isolation unit at Islington ROC



# Physical Damage - Substations

## Darfield Earthquake

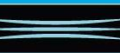
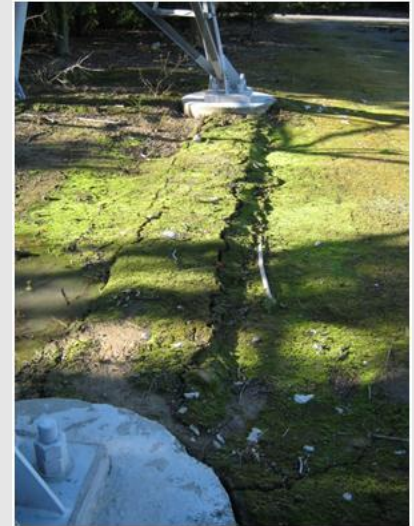
### Papanui Substation



- Liquefaction and minor differential settlement.
- Transformer bund walls and shallow pads with minor cracks



- ISL- PAP B Failed termination span at gantry connection.
- Liquefaction settlement around tower bases



# Physical Damage – Substations

## Christchurch Earthquake

### Bromley Substation



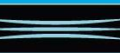
Failure of one 220 kV CVT  
BRY-ISL1 RFS



Failure of two HV bushings on  
T2 (66kV/11kV)



Damage to 11 kV switchboard;  
remained operational during the  
event – is being replaced



# Physical Damage – Substations

## Christchurch Earthquake

### Bromley Substation (cont)



- Intense liquefaction with silt and water covering part of the switchyard
- Foundations remained largely unaffected



- Only minor non-structural damage to control/relay building



# Physical Damage – Substations

## Christchurch Earthquake

### Papanui substation



- Damaged during September 2010 earthquake; further liquefaction and soil settlement around the transformer bunds
- New cracks in slab and bund walls



- Yielded holding down bolt supporting cable termination support structure.



# Physical Damage - Warehouse

## Christchurch Earthquake

### Addington Warehouse



- Collapsed shelving units.
- Similar damage occurred during Darfield earthquake.
- All shelf units to be replaced.

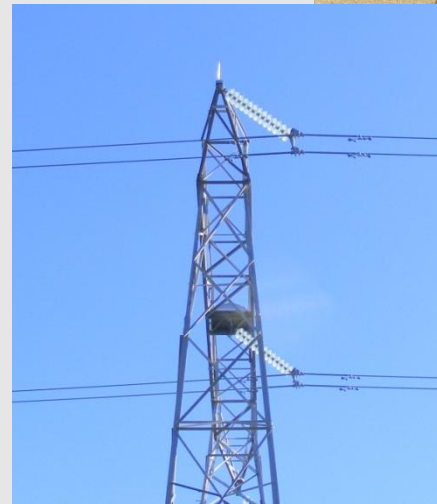
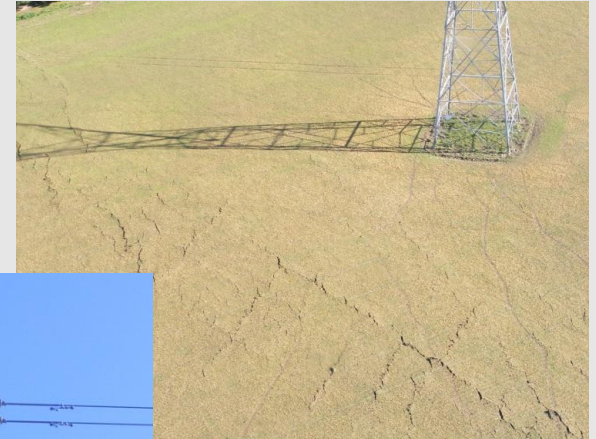


# Physical Damage - Transmission Lines

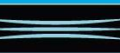
## Darfield Earthquake



- Liquefaction caused 3 towers on BRY-ISL A 220kV line to lean.
- Remediation to be carried following cessation of aftershocks.



- Fault line cutting the 220kV lines alignment at 45deg angle, strike-slip displacements of 2-4m.
- Insulators displaced (shown) and bent earthwire peaks resulted.

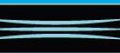


# Physical Damage - Transmission Lines

## Christchurch Earthquake

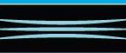


- Liquefaction around piles on BRY-ISL A 220 kV line and ISL-PAP A & B Lines.
- Towers remained stable and no loss of service occurred due to liquefaction.

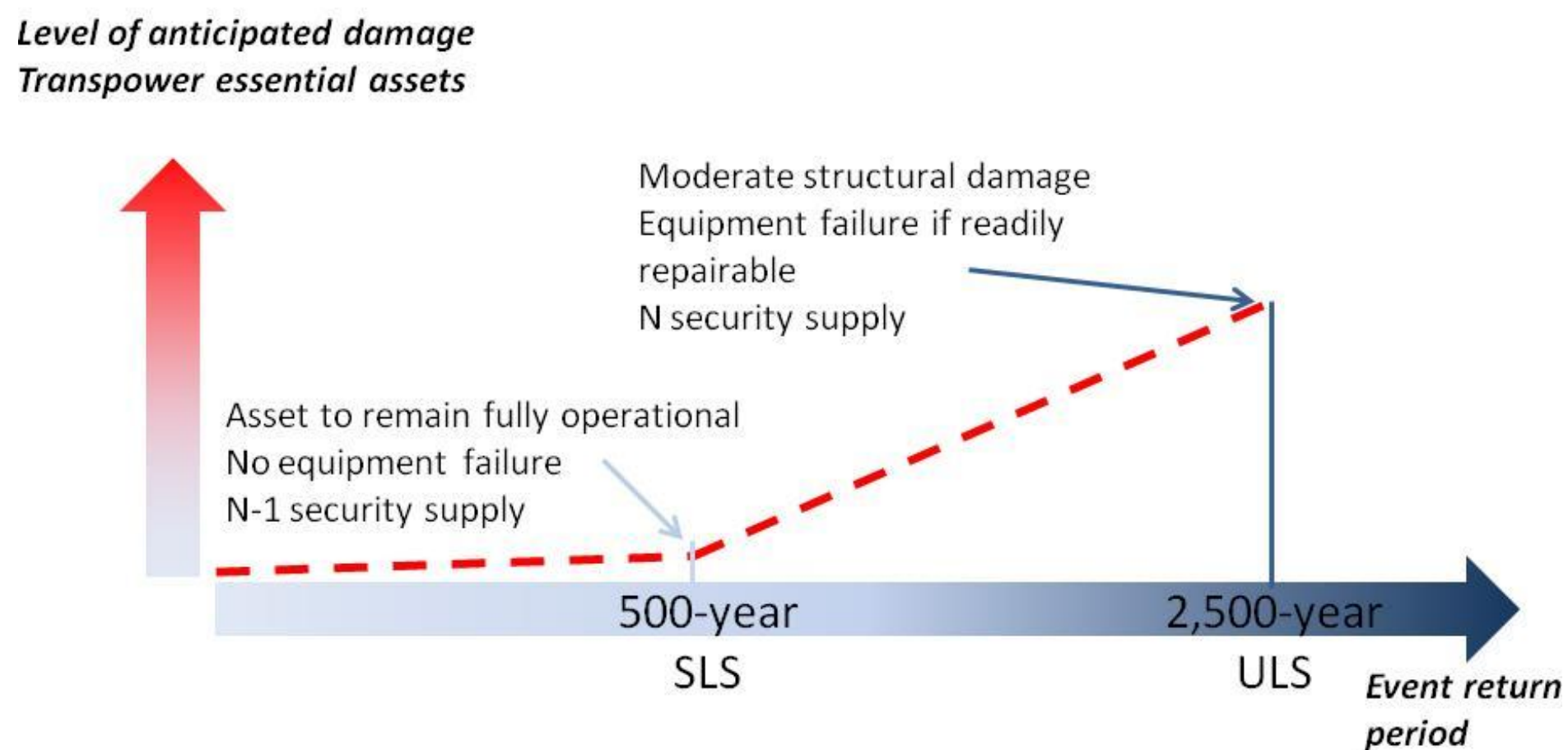


# Transpower Seismic Policy

- Civil Defence and Emergency Management Act 2002 require Transpower to “ensure it is able to function to the fullest possible extent, even though this may be at a reduced level, during and after an emergency”.
- Essential buildings and facilities are deemed Category 4 structures in terms of AS/NZS 1170.
- ULS – 2500 year return period event. Reduction permitted where spares available.
- SLS – 500 year return period event.
- Equipment purchase to comply with IEEE693:2005



# Transpower Seismic Policy



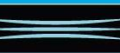
# Transpower Seismic Policy – Existing Assets

- Essential buildings (e.g. substation) shall be strengthened to, at least, 75% of new building standards
- Program to assess all essential buildings 2011, 2012
- Building strengthening work proposed 2012 to 2015
- Retrofit seismic restraints for transformers has been completed.
- Equipment shall be assessed with respect to remaining service life. Risk mitigation and availability of spares.

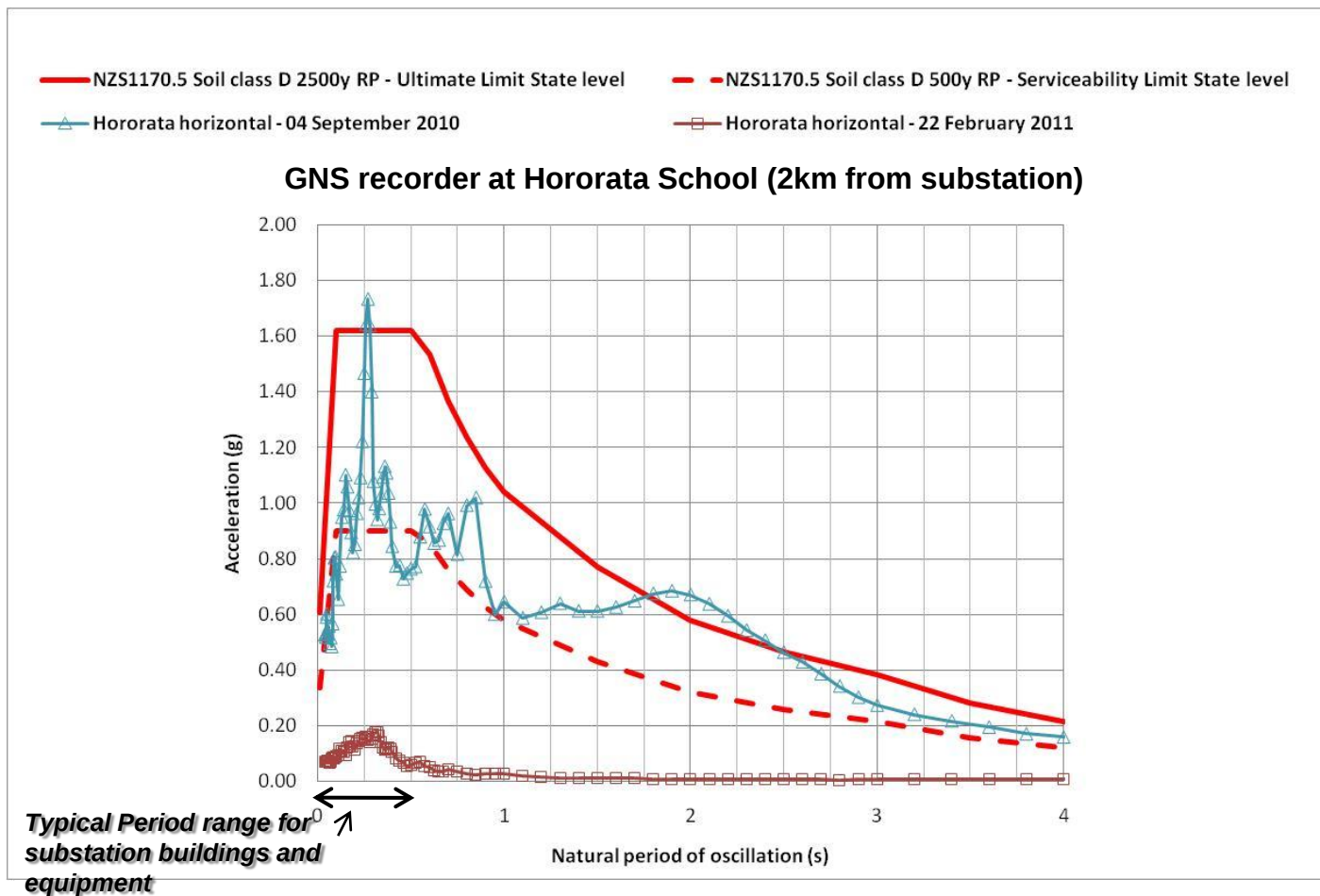


# Structural Performance

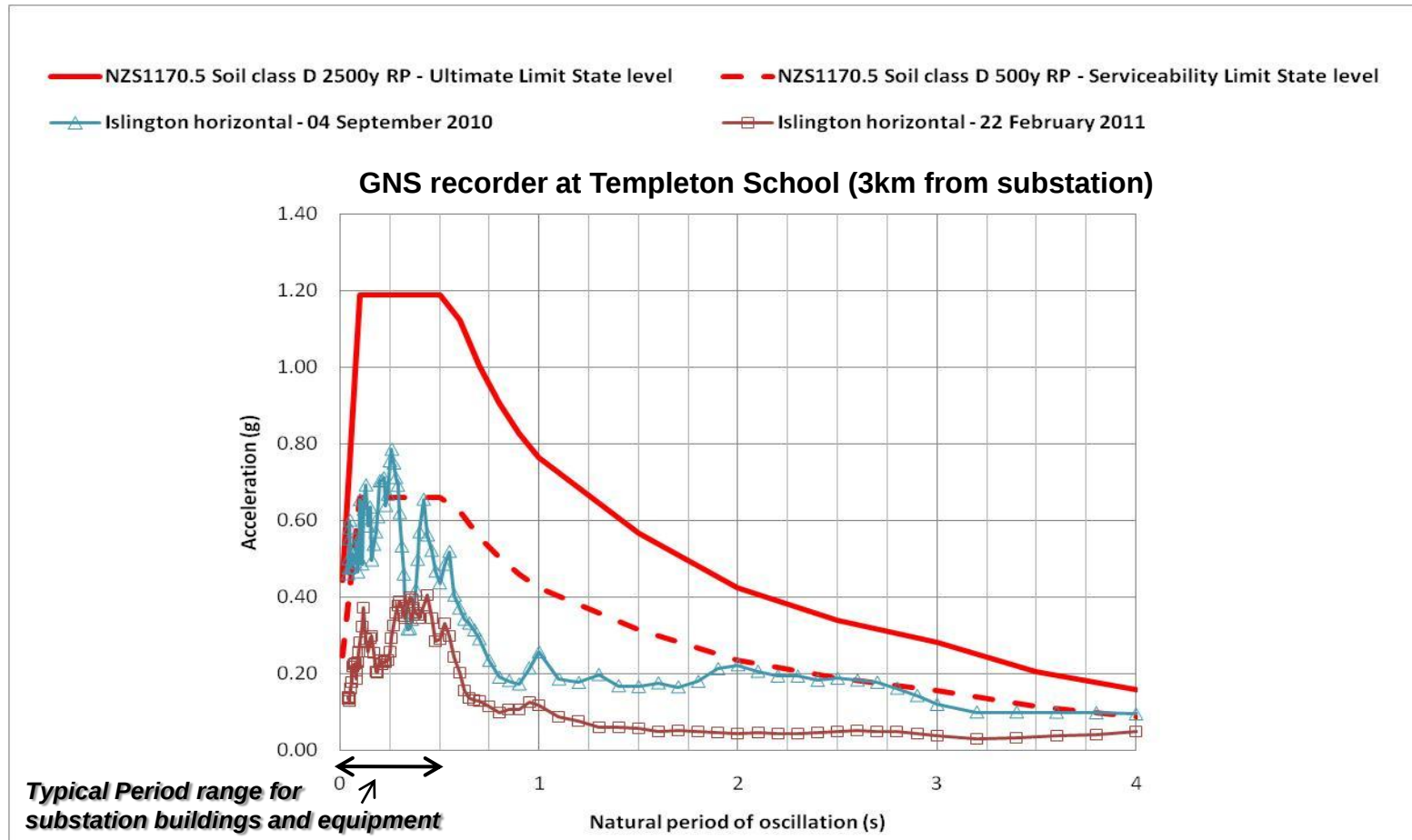
- Earthquake response spectra was generally in the range from SLS (500 year RP) to ULS (2500 year RP).
- Some damage and disruption was to be expected, but there were notable exceptions (e.g. ISL 220kV Surge Arrestor).
- The performance of aged infrastructure (pre seismic standards) was above expectations.
- The length of time to put the grid back in service was as much a function of the time it took to undertake safety inspections, given the transport issues post earthquakes, than poor structural performance.



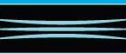
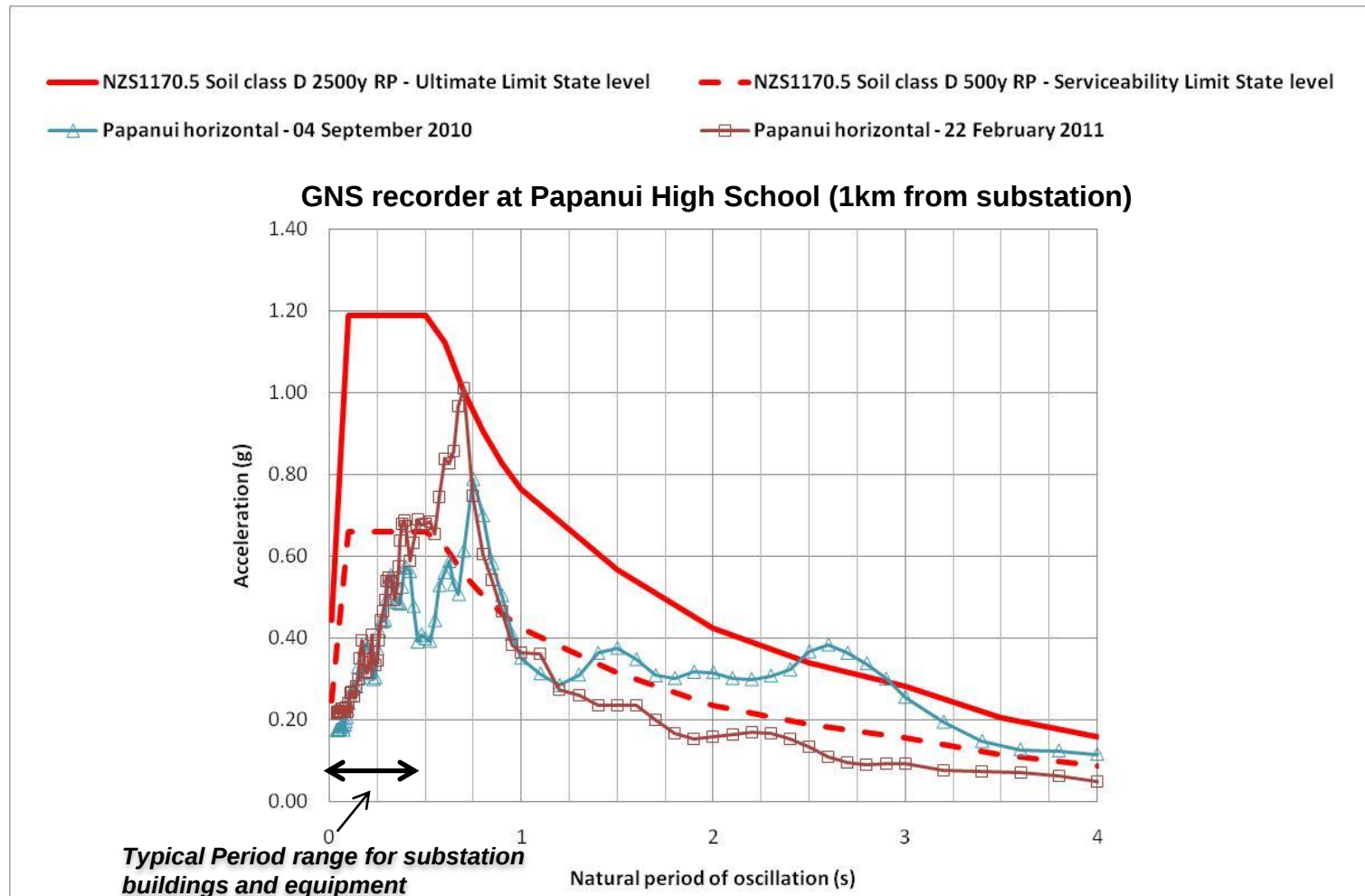
# Darfield vs Christchurch Earthquake Spectra Hororata Substation



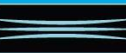
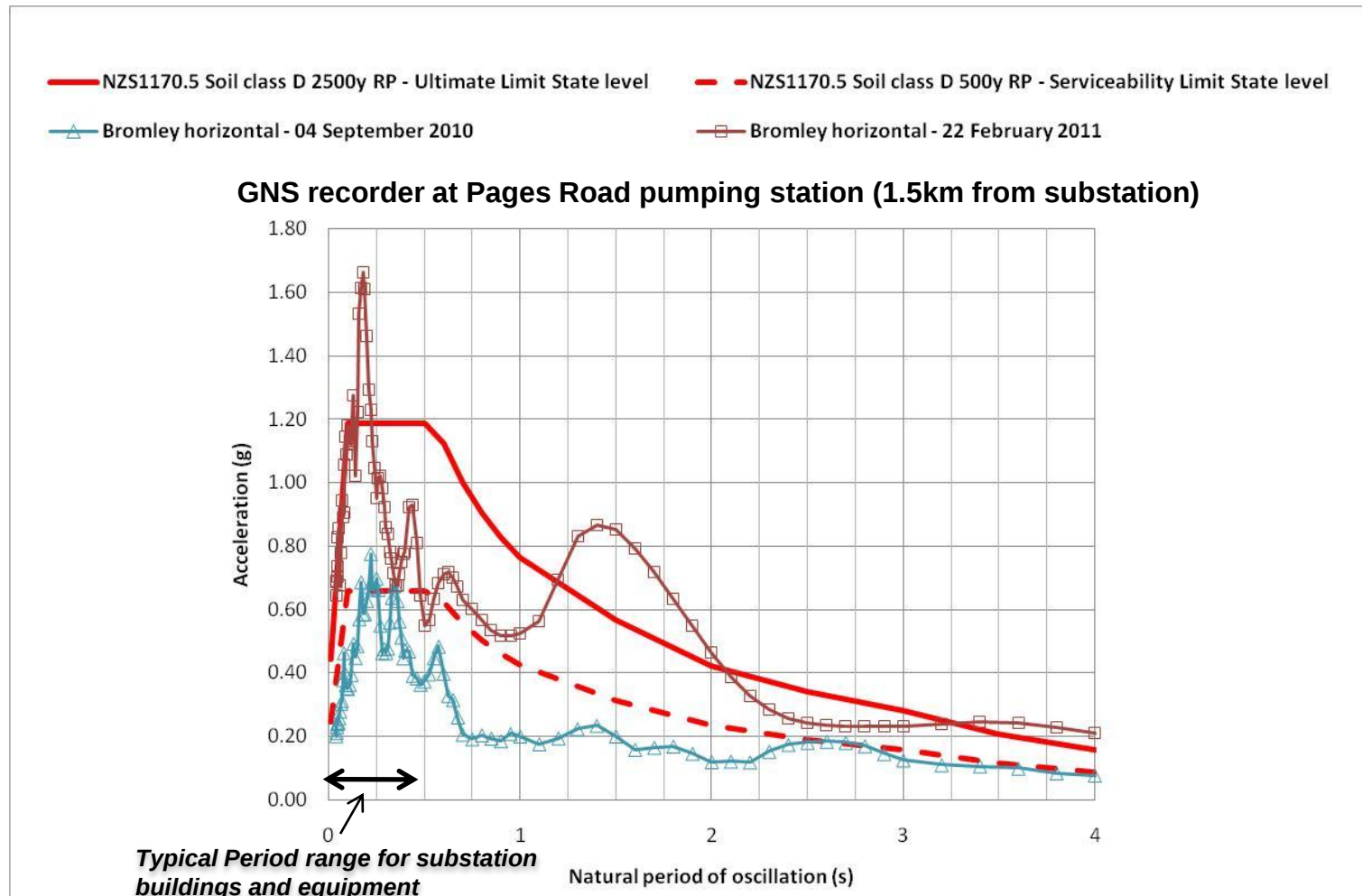
# Darfield vs Christchurch Earthquake Spectra Islington Substation



# Darfield vs Christchurch Earthquake Spectra Papanui Substation



# Darfield vs Christchurch Earthquake Spectra Bromley Substation



# Lessons learnt

- Priority - replace old mercury switches on transformers.
- The benefits of the seismic restraint programme undertaken in the 1990's following the Edgecumbe earthquake were realised in these events.
- Transpower is to continue to support the development of international seismic design standards for HV equipment.
- Further identification and mitigation of earthquake risk to the transmission network is required to provide resilience.



Transformer damage Edgecumbe 1987

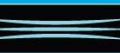


Transformer seismic restraints Hororata

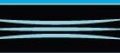


# Conclusions

- These earthquake events were a good test of the transmission network in the Canterbury region.
- Structure performance was satisfactory, but improvements can be made.
- The benefits of previous seismic strengthening programmes were realised in these events.
- Our work is not done:
  - participate in the development of international seismic design standards
  - identify and mitigate earthquake risk to the network
  - Continue to build a resilient system.



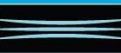
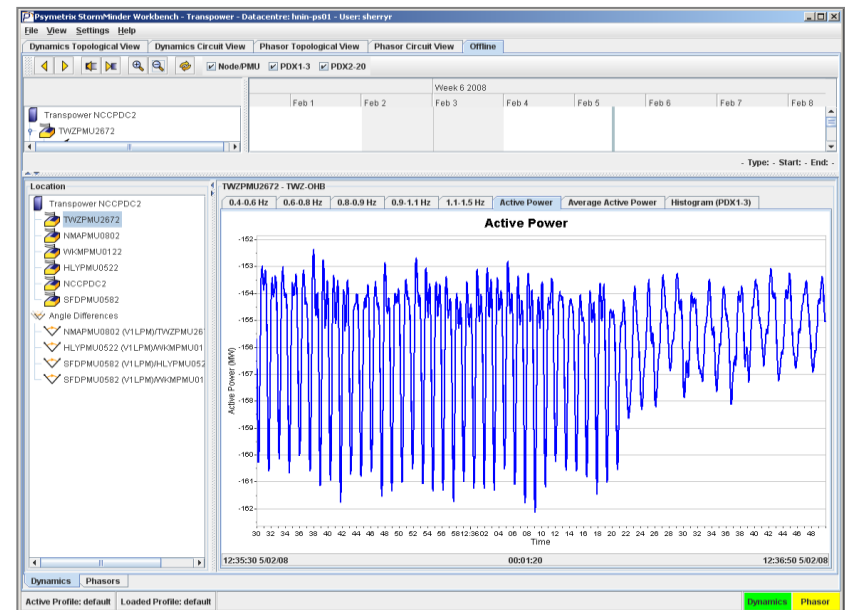
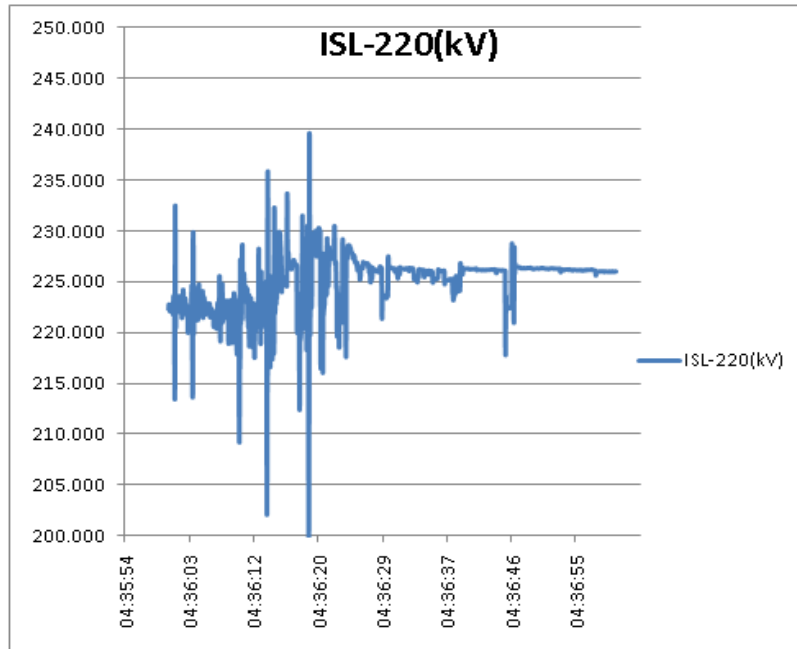
# Other slides



# Earthquake damage



# Monitoring technology to prevent instability



# Rugby World Cup preparedness

**Prepared by:** Fraser Clark  
General Manager Operations Development

## Information

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11 August 2011

### Requested actions

1. The Council is requested to:
  - (a) note the presentation from the System Operator on the measures that they have taken to safeguard reliability during the RWC; and
  - (b) identify any issues or potential issues that the System Operator and/or the Authority may need to consider.

### Context

2. This agenda item was agreed at the first SRC meeting.

# Electricity Infrastructure and Supply for Rugby World Cup 2011

SRC - August 2011

Kieran Devine

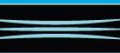
General Manager System Operations

TRANSPower



# RWC2011

- Why focus on electricity infrastructure
- Industry steering group
- Supply and demand
- Transpower planning and operational measures
- Vector planning and operational measures
- Summary
- Questions

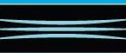
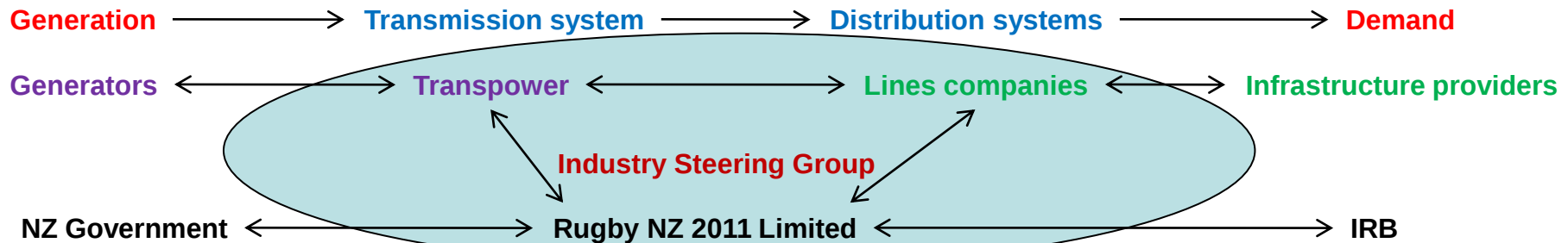
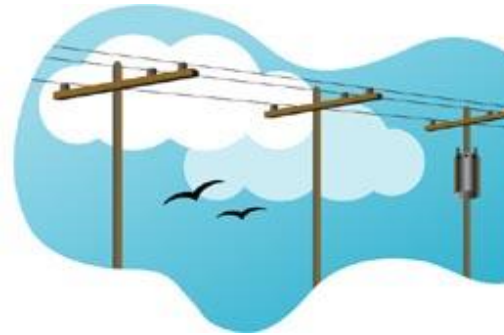
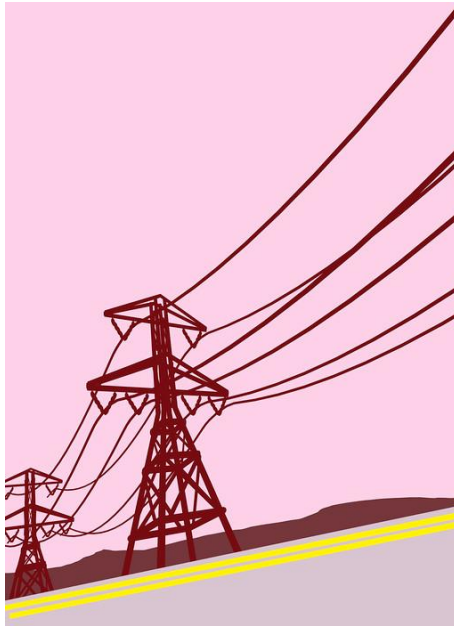
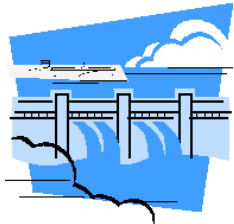


# The eyes of the World on NZ

- 1998 – Auckland Power Crisis
- 3 February 2009 – Broken shackle at Otahuhu
- 25 April 2009 – lights failure at North Harbour Stadium (Super 14 game)
- 30 October 2009 – Forklift operator at Metroport
- 25 January 2010 – Fire under a line in the Waikato



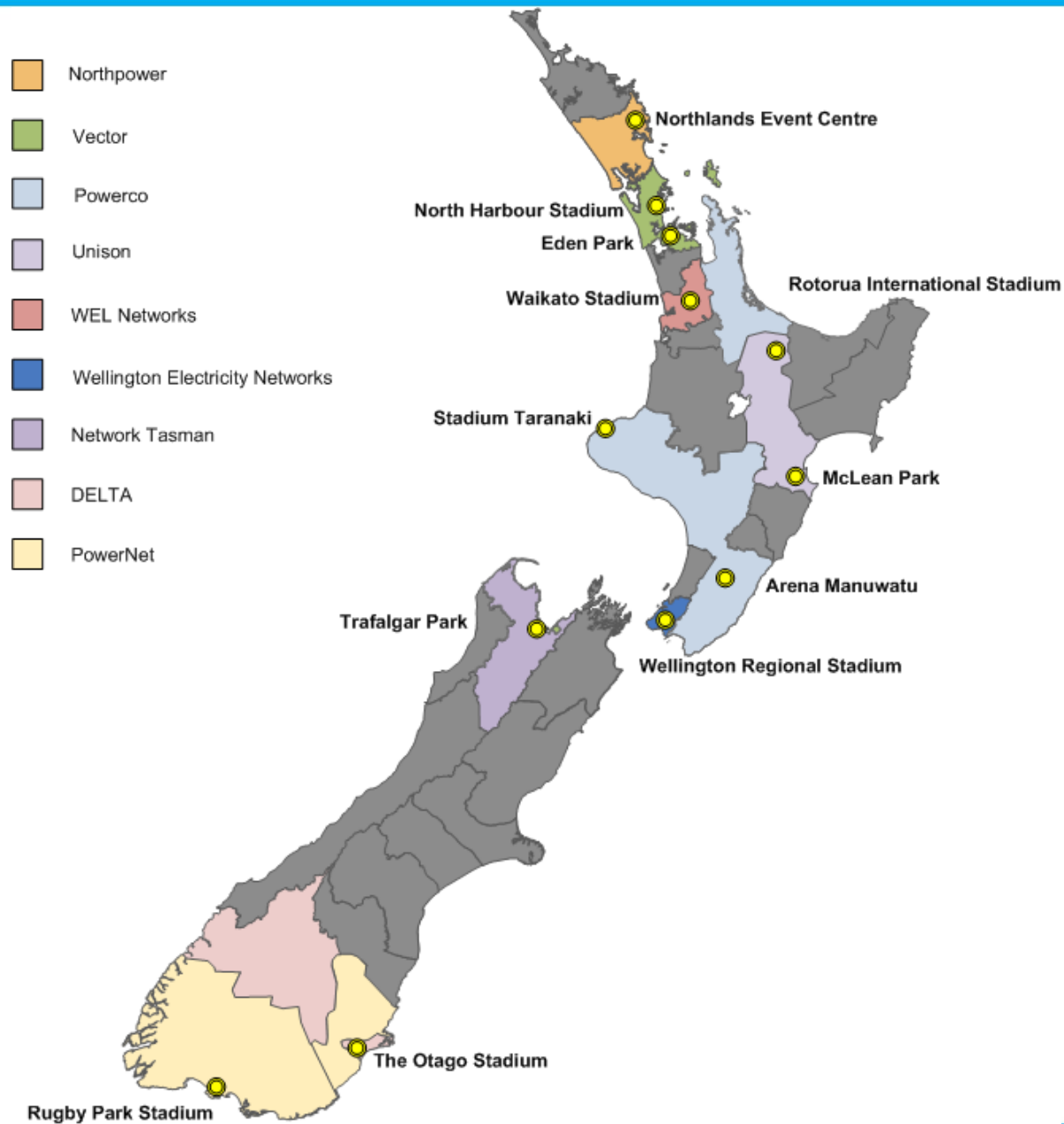
# Whole industry approach



# Industry Steering Group

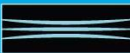
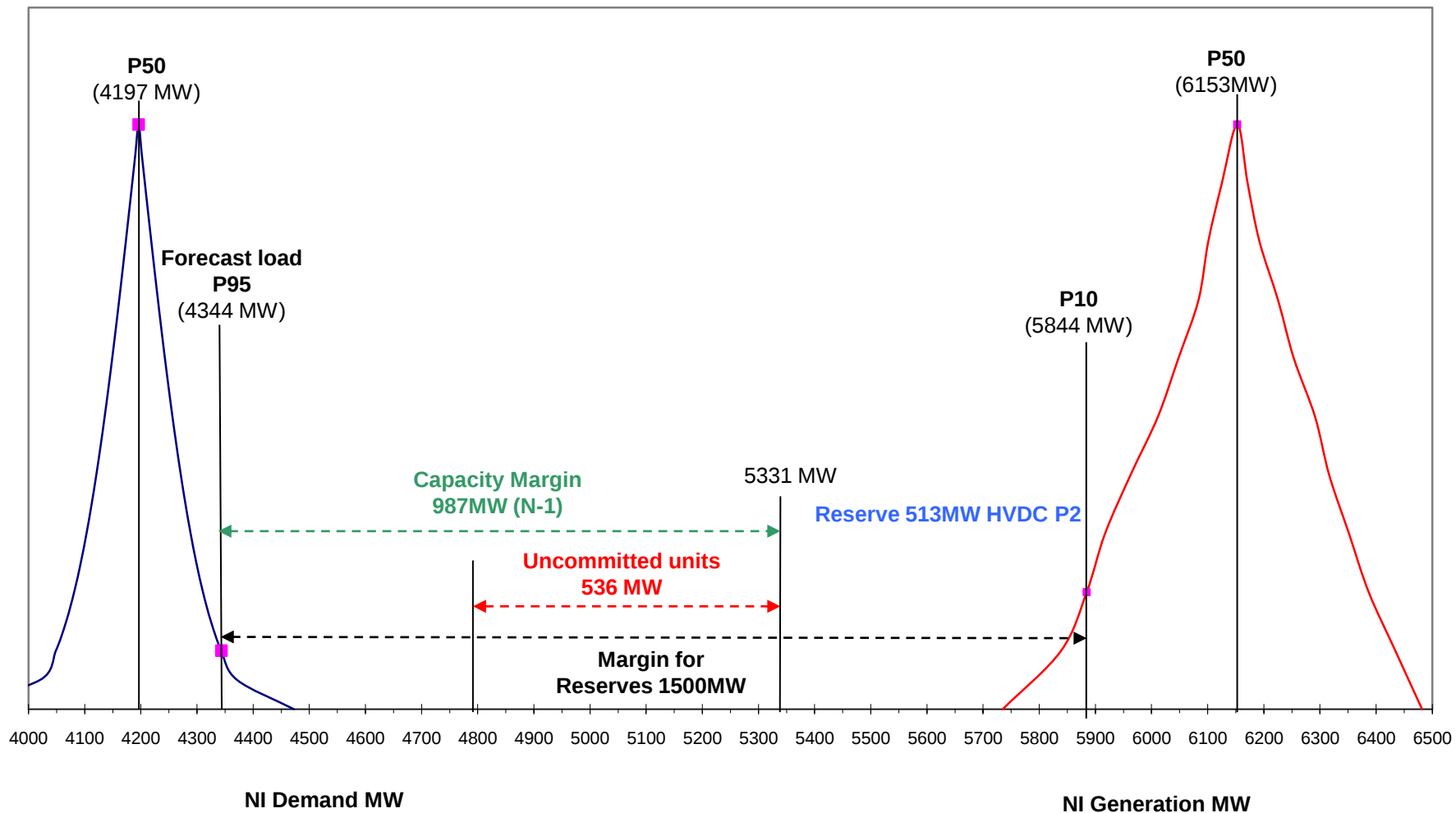


# Industry Steering Group



# RWC 2011 – Generation & Demand

North Island Demand and Generation Balance for RWC 2011 Sept - Oct  
7th February 2011 update. 2010 Peak Demand + 2.5%, + SFD 200MW + HVDC P1 Available



# Planning

- Transpower Planning
  - Network overview document prepared
  - Regional plans being developed
  - System Operator working with generators
  - Operational measures developed and issued
  - Impact of Christchurch games movement has been taken into account



# Operational Measures

- Planned work restrictions
- Operate with all network assets in service
- Work restrictions during matches
  - On Final, Semi and Quarter finals, no work at any substation or on any line
  - Regional restrictions for regional matches
- Expect sufficient generation to meet demand allowing for loss of a major generator



# Maintenance work restrictions

|                                    |                                     | Monday          | Tuesday         | Wednes<br>day   | Thursd<br>ay | Friday         | Saturda<br>y    | Sunday          | Mond<br>ay | Tuesday | Wednes<br>day | Thurs<br>day | Friday  | Satur<br>day | Sunda<br>y | Mond<br>ay | Tuesday  | Wednes<br>day | Thursd<br>ay | Friday   | Saturd<br>ay | Sunda<br>y | Mond<br>ay | Tuesday  | Wednes<br>day | Thursda<br>y | Friday       | Saturda<br>y | Sunday      | Monday   | Tuesday  |
|------------------------------------|-------------------------------------|-----------------|-----------------|-----------------|--------------|----------------|-----------------|-----------------|------------|---------|---------------|--------------|---------|--------------|------------|------------|----------|---------------|--------------|----------|--------------|------------|------------|----------|---------------|--------------|--------------|--------------|-------------|----------|----------|
| Region                             | Venue                               | 26/09/11        | 27/09/11        | 28/09/11        | 29/09/11     | 30/09/11       | 1/10/11         | 2/10/11         | 3/10/11    | 4/10/11 | 5/10/11       | 6/10/11      | 7/10/11 | 8/10/11      | 9/10/11    | 10/10/11   | 11/10/11 | 12/10/11      | 13/10/11     | 14/10/11 | 15/10/11     | 16/10/11   | 17/10/11   | 18/10/11 | 19/10/11      | 20/10/11     | 21/10/11     | 22/10/11     | 23/10/11    | 24/10/11 | 25/10/11 |
| Auckland / Whangarei               | Eden park                           |                 |                 |                 |              |                | ENG V SCO 20:30 |                 |            |         |               |              |         | QF2 20:30    | QF4 20:30  |            |          |               |              |          | SF1 21:00    | SF2 21:00  |            |          |               |              | Bronze 20:30 |              | Final 21:00 |          |          |
|                                    | North Harbour Stadium (NHS)         |                 |                 |                 |              | SA V SAM 20:30 |                 |                 |            |         |               |              |         |              |            |            |          |               |              |          |              |            |            |          |               |              |              |              |             |          |          |
|                                    | Northland Events Centre (NEC)       |                 |                 |                 |              |                |                 |                 |            |         |               |              |         |              |            |            |          |               |              |          |              |            |            |          |               |              |              |              |             |          |          |
| Northland / Auckland               |                                     |                 |                 |                 |              |                |                 |                 |            |         |               |              |         |              |            |            |          |               |              |          |              |            |            |          |               |              |              |              |             |          |          |
| Hamilton / Rotorua                 | Waikato Stadium                     |                 |                 |                 |              |                |                 | WAL v FIJ 18:00 |            |         |               |              |         |              |            |            |          |               |              |          |              |            |            |          |               |              |              |              |             |          |          |
|                                    | Rotorua International Stadium (RIS) |                 |                 |                 |              |                |                 |                 |            |         |               |              |         |              |            |            |          |               |              |          |              |            |            |          |               |              |              |              |             |          |          |
| Hamilton / Rotorua                 |                                     |                 |                 |                 |              |                |                 |                 |            |         |               |              |         |              |            |            |          |               |              |          |              |            |            |          |               |              |              |              |             |          |          |
| New Plymouth                       | Stadium Taranaki                    | WAL v NAM 19:30 |                 |                 |              |                |                 |                 |            |         |               |              |         |              |            |            |          |               |              |          |              |            |            |          |               |              |              |              |             |          |          |
| Napier                             | McLean Park                         |                 | CAN v JAP 17:00 |                 |              |                |                 |                 |            |         |               |              |         |              |            |            |          |               |              |          |              |            |            |          |               |              |              |              |             |          |          |
| Palmerston North/ Wellington       | Area Manawatu (AM)                  |                 |                 | GEO v ROM 19:30 |              |                |                 | ARG v GEO 13:00 |            |         |               |              |         |              |            |            |          |               |              |          |              |            |            |          |               |              |              |              |             |          |          |
|                                    | Wellington Regional Stadium (WRS)   |                 |                 |                 |              |                | FRA v TON 18:00 | NZ v CAN 15:30  |            |         |               |              |         | QF1 18:00    | QF3 18:00  |            |          |               |              |          |              |            |            |          |               |              |              |              |             |          |          |
| Palmerston North/ Wellington       |                                     |                 |                 |                 |              |                |                 |                 |            |         |               |              |         |              |            |            |          |               |              |          |              |            |            |          |               |              |              |              |             |          |          |
| Nelson                             | Trafalgar Park                      |                 | ITA v USA 19:30 |                 |              |                | AUS v RUS 15:30 |                 |            |         |               |              |         |              |            |            |          |               |              |          |              |            |            |          |               |              |              |              |             |          |          |
| Dunedin                            | Otago Stadium                       |                 |                 |                 |              |                |                 | IRL v ITA 20:30 |            |         |               |              |         |              |            |            |          |               |              |          |              |            |            |          |               |              |              |              |             |          |          |
| Invercargill                       | Rugby Park Stadium                  |                 |                 |                 |              |                |                 |                 |            |         |               |              |         |              |            |            |          |               |              |          |              |            |            |          |               |              |              |              |             |          |          |
| Nationwide or regional restriction |                                     |                 |                 |                 |              |                |                 |                 |            |         |               |              |         |              |            |            |          |               |              |          |              |            |            |          |               |              |              |              |             |          |          |

|  |                        |
|--|------------------------|
|  | Nationwide restriction |
|  | Regional restriction   |



# Major Projects

- HVDC Pole 1 decommissioning delayed
- Only works in non critical areas
- No road trenching works in Auckland city
- Impact of RWC2011 factored into project delivery



# Result

