

# System Security Forecast 2010

## Part B

### Approach & Assumptions



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

SYSTEM OPERATOR

*Keeping the energy flowing*

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# I M P O R T A N T

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## Contact Details

|            |  |
|------------|--|
| Address:   | Transpower New Zealand Ltd<br>96 The Terrace<br>PO Box 1021<br>Wellington<br>New Zealand |
| Telephone: | +64 4 495 7000   |
| Fax:       | +64 4 498 2671   |
| Email:     | <a href="mailto:system.operator@transpower.co.nz">system.operator@transpower.co.nz</a>   |
| Website:   | <a href="http://www.systemoperator.co.nz">http://www.systemoperator.co.nz</a>            |

## 1. INTRODUCTION: SECURITY FORECAST APPROACH AND ASSUMPTIONS

The purpose of this document is to explain the approach and assumptions used in the security analysis presented in Part C and the analysis for frequency management presented in Part D. The approach and assumptions for this System Security Forecast (SSF) are different to previous SSFs.

This SSF is a prediction of the System Operator's ability to meet its principal performance obligations under Part 7 of the 'Code' and the provision of the SSF to the Electricity Authority is a requirement of the 'Code'.

The System Operator's Principal Performance Obligations (PPO) can be summarised as follows:

- Avoid cascade failure;
- Manage frequency;
- Take reasonable action to maintain other standards (harmonic levels, voltage flicker levels, voltage imbalance).

The System Operator's ability to meet the first two PPOs is assessed in this SSF. The assessment is carried out in the context of the policies and means used by the System Operator to meet the PPO as set out in the Policy Statement.

The Policy Statement sets out the policies and means applied by the System Operator in taking reasonable action to maintain standards relating to harmonic levels, voltage flicker levels and voltage imbalance. There is no analytical power system analysis that can be done to assess the System Operator's ability to meet the "other standards" PPO. The System Operator has no reason to believe that the policies and means set out in the Policy Statement in relation to the "other standards" PPO will be inadequate over the ten year period.

Analysis performed in this SSF considers only existing generation and transmission assets with committed investment projects of which the System Operator has been made aware of. The capability of the existing power system (and committed projects) to meet the load growth scenarios is assessed and situations where all demand may not be able to be met without further enhancement of the power system are identified.

### 1.1 REPORT STRUCTURE

The analysis is undertaken on an Island by Island basis. Part C of the SSF discusses the North and South Island power system capability. Each Island is divided into separate electrical regions and the security of these regions is discussed.

The North Island is divided into nine regions and the South Island into four regions. Each of the thirteen regional analysis' are set out in a standard format and include the following key sections:

- Network overview;
- Demand and generation balance;

- Key power system capability issues on a regional and local basis.

### 1.1.1 STUDY APPROACH

Short term operational issues associated with security and power transfer into each region are considered for both summer and winter over the three year study period.

The analysis includes:

- Analysis of historical demand trends has been used when determining prudent and expected demand forecasts for the study period from winter 2011 to 2013;
- The formulae for existing SPD constraints relating to certain power system issues are included;
- Generic contingency plans for management of power system issues are outlined;
- Indicative power system capability limits applying during notified outages of transmission plant are provided;
- Short term asset capabilities (for transmission circuits and transformers) are utilised where applicable;
- Power system capability limits on “Limit Group<sup>1</sup>” for management of N-1 and N-1-1 events are identified as required.

### 1.1.2 STUDY ASSUMPTIONS

In order to interpret the findings of the SSF, readers should be aware of the strengths and limitations of the underlying assumptions and models used. The following sections describe the base assumptions used in preparing this SSF.

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<sup>1</sup> Power system capability limits may affect one or more grid exit/injection point. The group of these grid exit points and grid injection points affected by the power system capability limit is referred to as the “limit group”. The power system capability issues are listed in terms of limit group. This makes it easy to determine at a glance what power system capability issues affect a particular limit group or grid exit point or grid injection point.

## 2. STUDY APPROACH

### 2.1 SYSTEM OPERATOR PRINCIPLE PERFORMANCE OBLIGATIONS

This section outlines the approach taken in preparing this SSF in order to meet the System Operators Principle Performance Obligations. The approach outlined in the first subsection (“power system capability analysis”) is different in some aspects to the approach used in previous SSFs. The main change is a shift in emphasis to detailed analysis of the short term (three years ahead) operational management of the power system.

The approach outlined in the second subsection (“manage frequency”) is the same as that used in previous SSFs.

#### 2.1.1 POWER SYSTEM CAPABILITY

The performance of the power system during and following contingent events and extended contingent events is assessed and compared against target quality conditions and limits in the Policy Statement. The events and the target quality conditions and limits (as contained in the Policy Statement) are shown in the following Table 2-1.

Table 2-1 Summary of Policy Statement Events and Target Quality Conditions

| Policy Statement Event  | Target quality conditions and limits during event (for security analysis)   |
|---|---|
| <p><i>Contingent Event</i></p> <p>a) <i>The loss of a transmission circuit</i></p> <p>b) <i>The loss of a HVDC pole</i></p> <p>c) <i>The loss of a single generating unit</i></p> <p>d) <i>The loss of both circuits of a double circuit line where the system operator has determined a high level of likelihood of occurrence based on historical information</i></p> <p>e) <i>The loss of both transmission circuits of a double circuit line when the system operator has been advised of a temporary change to environmental or system conditions that give reason to believe there is a high likelihood of occurrence of the simultaneous loss of both circuits</i></p> | <p>No asset exceeds its stated capability</p> <p>Grid voltage will be within advised asset capability</p> <p>No demand is interrupted post event, other than contracted reserves and/or interruptible load contracted or pre-arranged to be interrupted</p> |
| <p><i>Extended Contingent Events</i></p> <p>a) <i>The sudden loss of the HVDC bipole</i></p> <p>b) <i>The loss of a bus section</i></p> <p>c) <i>The loss of an interconnecting transformer</i></p>   | <p>No asset exceeds its stated capability</p> <p>Grid voltage will be within advised asset capability</p> <p>AUFLS may be used</p>  |
| <p><i>Stability Events</i></p> <p>a) <i>A contingent event</i></p> <p>b) <i>An extended contingent event</i></p>  | <p>Stability of the power system is maintained</p>  |

**Note:** frequency quality conditions and limits are not listed in the table.

#### 2.1.2 FREQUENCY MANAGEMENT

Part 7 of the Electricity Industry Participation Code contains six objectives for the management of frequency by the System Operator:

- Maintain frequency in the normal band;
- Manage frequency during momentary fluctuations;

- Limit rate of occurrences of momentary fluctuations;
- Recover quickly from a fluctuation;
- Manage time error;
- Eliminate time error once a day.

The policies and means applied by the System Operator to meet the frequency PPO are set out in the Policy Statement. The System Operator procures ancillary services (frequency regulating reserves, instantaneous reserves and over frequency reserves) to meet frequency obligations.

The assessment of the “manage frequency” PPO is based on determining whether the policies and means set out in the Policy Statement are adequate during the three year study period. It is assumed that current reserve providers will continue to offer these reserves into the market at present levels, throughout the three year study period.

## 2.2 POWER SYSTEM ANALYSIS

The identification of a system capability limit ensures that target quality conditions and limits can be met during and following the event. Some limits constrain the dispatch of generation and others may require load management.

Power system issues are identified through two independent processes: deterministic security analysis and operational experience.

### 2.2.1 DETERMINISTIC SECURITY ANALYSIS

Six study cases representing the winter and summer peak loads for 2011, 2012 and 2013 are developed. Each case is analysed using “DIgSILENT” ‘Power factory’ software. The software permits a full AC power system analysis of each study case and identifies power system issues involving assets that exceed thermal ratings, busbar voltages outside range and static voltage stability. Emphasis is placed on contingent events and extended contingent events (e.g. interconnecting transformer outages) as defined in the Policy Statement. Each issue identified with this process is noted for further analysis.

#### 2.2.1.1 *Voltage Stability and Power System Capability Limits*

A static analysis method of determining voltage stability has been used in this report. The point of collapse limit due to voltage instability is determined by the amount of load at which the point of collapse occurs. A margin of 5% is then applied to the load.

Power system capability limits due to voltage stability are sensitive to power system model parameters (e.g. load power factor) and power system conditions (e.g. generation patterns). Any stated power system capability limit due to voltage stability needs to have power system model parameters and conditions used in determining the limit also clearly stated.

Power system capability transfer limits to avoid voltage instability are typically determined to an accuracy of  $\pm 10$  MW. This accuracy is comparable with the impact on voltage stability limits of

relatively small changes in assumptions and the uncertainty inherent in the power system model parameters and analysis. In some cases, voltage during and following a contingent event will drop below advised asset capability before voltage instability is entered and the power system limit will be caused by asset capability rather than voltage stability.

### 2.2.2 OPERATIONAL EXPERIENCE

Deterministic Security Analysis can be expected to identify most (but not necessarily all) power system issues. Known power system issues associated with dynamic stability or transfer capability are commented on as necessary.

### 2.2.3 ANALYSIS OF ISSUES

Analysis is carried out for the power system with all assets in service and for selected planned outages of certain assets. Sensitivity analysis is undertaken to determine how limitations are influenced by:

- Load power factors in a region or area;
- Generation scheduling across the power system.

#### 2.2.3.1 *Sensitivity Analysis*

Some power system capability limits of the grid are analysed using sensitivity factors. Sensitivity factors are expressed as a fraction which can be positive or negative to reflect loading increases or decreases due to changes in regional generation. A positive sensitivity factor indicates that circuit loading increases for an increase in regional generation. A negative sensitivity factor indicates that circuit loading decreases for an increase in regional generation.

The mathematical equation relating sensitivity factors to circuit loading is:

$$P_1 = P_0 + sf \times \Delta G$$

Where  $P_1$  is the new loading on the circuit,  $P_0$  is the initial loading on the circuit,  $sf$  is the sensitivity factor and  $\Delta G$  is the increase in regional generation.

The sensitivity factor for a circuit with regard to a regional generation or demand of 0.5 indicates that for an increase in 1 MW of regional generation or demand, the increase in loading on the circuit is 0.5 MW. If the initial loading on the circuit ( $P_0$ ) is 100 MW for a given regional generation or demand then an increase of 10 MW in regional generation or demand will increase the loading ( $P_1$ ) on the circuit to 105 MW.

#### 2.2.3.2 *Constraint Lines*

Sensitivity factors for different regional demands and generation can be combined to determine constraint lines. Constraint lines are used to show boundaries where the loading on the circuit is kept to stated capability. The following Figure 2-1 shows a constraint line diagram. The axes are the amount of generation in regions A and B. The maximum amounts of generation in regions A and B

are indicated by the vertical and horizontal dashed lines. The constraint line goes through points X and Y.

The power system limits required to avoid the loading on the circuit exceeding stated capability during contingent events are indicated by the constraint line. The shaded area shows operation within power system limits.

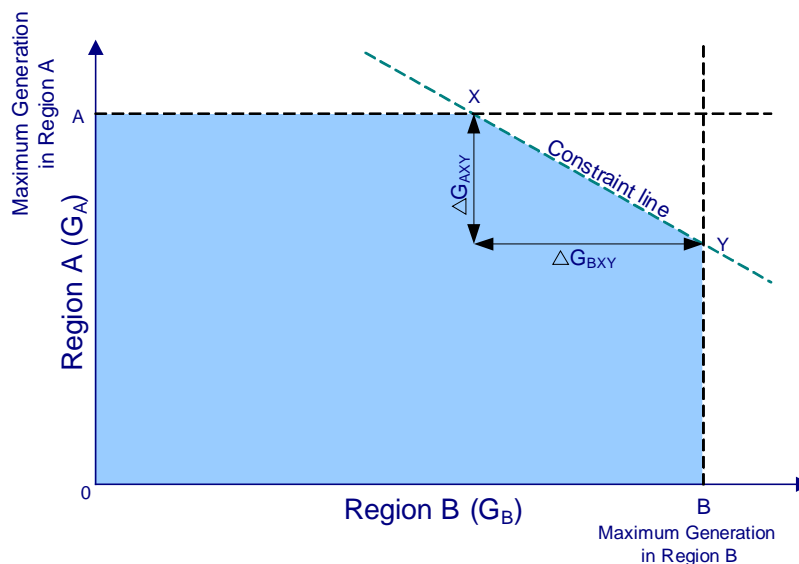


Figure 2-1 Construction of Constraint Lines

The constraint line shows the boundaries where the loading on the circuit is kept to stated capability. Assume that the initial operating point is at point X. An increase in the amount of generation in region B of  $\Delta G_{BXY}$  will require a reduction in the amount of generation in region A of  $\Delta G_{AXY}$  to avoid the loading on the circuit exceeding stated capability following a contingent event.

The formula for a constraint line is:

$$P + sf_A \times G_A + sf_B \times G_B = 0$$

Where subscripts A and B refer to regions A and B and P, there is a constant related to the initial loading of the circuit. Where the circuit is loaded at stated capability, any increase in the amount of generation or demand in region ( $\Delta G_A$ ) must be offset by a reduction in generation or demand in region B of an amount  $\Delta G_B = sf_A/sf_B \times \Delta G_A$  if the loading on the circuit is to remain at stated capability.

### 2.2.3.3 Risk Exposure

Power system capability limits are determined for each power system capability issue. These power system capability limits are determined assuming that no operational measures are in place. For power system capability limits applying to contingent events, with all assets are in service, an assessment of the exposure to risk is undertaken. Power system capability limits applying during planned outages do not have a risk assessment as the timing of planned outages is determined to minimise disruption to security.

The following Table 2-2 shows the analysis carried out for each type of event.

*Table 2-2 Summary of Policy Statement Events and Risk Exposure*

| Policy Statement Event                                 | Power System Limit   | Risk Exposure  |
|--|--|--|
| <i>Contingent Event and Extended Contingent Events</i> | <p>The power system load (or transfer) limit is determined such that during and following the contingent event</p> <p>No asset exceeds its stated capability</p> <p>Grid voltages remain within the advised asset capability</p> <p>Voltage stability is preserved</p> | <p>Power System Load limit is compared against forecast load duration curves. Where the forecast load exceeds the power system load limit and in the absence of enhancements to power system capability, demand curtailment will be required during and following a contingent event or extended contingent event</p>  |
| <i>Planned Outages and Contingent Events</i>           | <p>The power system load (or transfer) limit is determined such that above quality conditions and limits are maintained during and following the contingent event</p>  | <p>No assessment of risk exposure is made. Planned outages go ahead when power systems conditions are favourable and operational measures in place so that the occurrence of a contingent event during the planned outage will not cause quality conditions and limits not to be met</p> <p>The window of opportunity for planned outages can be limited by power system load limits</p> |
| <i>Stability Events</i>                                | <p>The power system load (or transfer) limit is determined such that power system stability is maintained during and following the stability event</p>   | <p>No assessment of risk exposure is made</p>  |

The duration of exposure to risk for a particular contingent event is calculated using forecast annual load duration curves. The risk exposure for an event is calculated in terms of the percentage of time per year that the demand is at risk of not being fully supplied.

The power system capability limit is compared with the medium forecast load duration curves. This comparison will provide an indication of the amount of time that forecast demand will be above the capability limit.

Using medium demand forecast gives an expected (in a statistical sense) estimate of the amount of the time that the demand will exceed the power system capability limit. The demand in a future year has a 50% chance of being above the medium forecast and a 50% chance of being below the medium forecast.

### 3. FREQUENCY MANAGEMENT ANALYSIS

#### 3.1 FREQUENCY MANAGEMENT ANALYSIS

One of the PPOs concerns the management of power system frequency. The policies and means used by the System Operator to meet this PPO are set out in the Policy Statement. The System Operator procures ancillary services (frequency regulating reserves, instantaneous reserves and over-frequency reserves) to comply with the frequency principal performance obligation.

The System Operator uses the framework set out in the ancillary services Procurement Plan to procure frequency regulating reserves, instantaneous reserves and over-frequency reserves. Ancillary services providers are contracted to provide these reserves. The adequacy of these means to meet power system demand over the next three years is forecast.

The approach is largely qualitative. A simplified analysis is used to support a forecast of the System Operator's ability to meet the frequency PPO. This analysis assesses whether there is sufficient generation capacity to meet future energy and reserves requirements.

##### 3.1.1 FREQUENCY MANAGEMENT ASSUMPTIONS

The following assumptions are made:

- The asset capability information provided by asset owners can be relied upon to be accurate and valid over the next three years;
- Ancillary service providers continue to offer ancillary services over the next three years at the same levels currently offered and provide ancillary services as contracted;
- Asset owners are compliant with the asset owner performance obligations and technical codes of Part 8 of the 'Code';
- There is insignificant embedded generation that is non-compliant with the asset owner performance obligations and technical standards concerning frequency.

##### 3.1.2 FREQUENCY MANAGEMENT

Three areas are assessed:

###### 3.1.2.1 *Frequency Regulation Management*

The maintenance of frequency in the normal band and the management of time error are managed through frequency regulating reserves.

###### 3.1.2.2 *Under Frequency Management*

Sudden drops in system frequency resulting from events on the power system are managed through instantaneous reserves.

### 3.1.2.3 *Over Frequency Management*

The sudden loss of a large load or the HVDC link can cause system frequency to rapidly increase. Management of such events is through over-frequency management. Over-frequency management is achieved by the use of over-frequency reserves.

## 4. POWER SYSTEM CONFIGURATION & ASSET CAPABILITY

The base network assumed in the analysis is equivalent to that as at 2<sup>nd</sup> July 2010 and is shown geographically and in single line diagram form in Part C.

The capability of assets in the power system is assumed to be that declared by asset owners as at 2<sup>nd</sup> July 2010, plus the indicated capability of any projects that pass the committed investment test.

### 4.1 DEFINITION OF A COMMITTED PROJECT

Committed changes are:

- The actual proposed projects that satisfy a number of criteria indicating that they are extremely likely to proceed in the near future, for instance:
  - Land has been acquired for construction of the project;
  - Planning consents, construction approvals and licences have been obtained;
  - Construction has begun or a firm commencement date has been set;
  - Contracts for supply and construction have been finalised;
  - Financing arrangements must be largely completed.
- The removal or reduction of stated capability of existing assets where a final decision has been made to decommission or reduce the capability on or after a specified date where:
  - such changes have been publicly communicated and contracts have been put in place for the purpose of decommissioning or reduced capability, or
  - consents or other agreements required for the continued operation of the assets expire or are expected to expire and in respect of which no reasonable certainty of renewal is available.
- As a precaution to unexpected early winter loads, the analysis of committed projects scheduled for completion in May and June have been pushed to the following season.

### 4.2 COMMITTED GENERATION PROJECTS

The proposed generation projects that have passed the SSF Committed Investment Test as of 2<sup>nd</sup> July 2010 are as follows in Table 4-1. Note that there were other projects that did not pass the committed test as per the above date. These upgrades and additional proposals will be considered in future SSF updates.

*Table 4-1 Summary of Committed Generation*

| Name                       | Type | Capacity (MW) | Region               | Commissioning Date | Status of project |
|----------------------------|------|---------------|----------------------|--------------------|-------------------|
| <i>Te Rere Hau Stage 4</i> | Wind | 15            | Wellington           | 2010/11            | Commissioning     |
| <i>Te Uku</i>              | Wind | 64            | Central North Island | 2010/11            | Commissioning     |
| <i>Mahinerangi Stage 1</i> | Wind | 36            | Southland            | Jan-Mar 2011       | Committed         |

| Name                | Type       | Capacity (MW) | Region               | Commissioning Date | Status of project                       |
|---------------------|------------|---------------|----------------------|--------------------|---|
| <i>Taharoa C</i>    | Wind       | 48            | Waikato              | 2011               | Committed – on hold                     |
| <i>Te Mihi</i>      | Geothermal | 220           | Central North Island | Unknown            | Committed – on hold                     |
| <i>Central Wind</i> | Wind       | 120           | Central North Island | Unknown            | Expected to be Committed by August 2010 |
| <i>Ngatamariki</i>  | Geothermal | 100           | Central North Island | Late 2012/2013     | Consenting process                      |
| <i>Turitea</i>      | Wind       | 288           | Wellington           | July 2015          | Consenting process                      |

### 4.3 COMMITTED GRID UPGRADES

The proposed network upgrades that have passed the SSF Committed Investment Test as of 2<sup>nd</sup> July 2010 are as follows in Table 4-2. Note that there were other upgrades that did not pass the committed test as per the above date. These upgrades and additional proposals will be considered in future SSF updates.

Table 4-2 Summary of Committed Grid Upgrades

| Asset  | Committed Upgrades   | Region               | Commissioning Date | Status    |
|--|--|----------------------|--------------------|-----------|
| <b>North Island</b>  |  |                      |                    |           |
| <i>MDN 220/110/11 kV Interconnecting Transformer</i>             | New interconnecting Transformer at Marsden to replace T1   | Northland            | March 2009         | Completed |
| <i>Kaitimako (KMO) substation</i>                                | New substation with 1x 75 MVA 110/33 kV supply transformer   | Bay of Plenty        | July 2009          | Completed |
| <i>Bunynthorpe – Tokaanu A &amp; B 220 kV circuits</i>           | Thermal upgrade – rating increases from 202/247 MVA to 308/335 MVA per circuit   | Central North Island | July 2009          | Completed |
| <i>Arapuni-Pakuranga &amp; Otahuhu-Pakuranga 110 kV circuits</i> | Dismantling the existing 110 kV Arapuni to Pakuranga circuit and reconnecting the unused 110 kV Otahuhu-Pakuranga circuit            | Northland & Auckland | October 2009       | Completed |
| <i>Otahuhu – Penrose 220 kV circuits 5 &amp; 6</i>               | Upgrade terminal equipment – rating increases from 455/455 MVA to 469/492 MVA per circuit  | Auckland             | November 2009      | Completed |
| <i>Nga Awa Purua (NAP) Substation</i>                            | New substation to connect Nga Awa Purua geothermal power station NAP substation connects to OKI-WRK line via a single 220 kV circuit | Central North Island | November 2009      | Completed |
| <i>Penrose (PEN) T7</i>  | New 250 MVA interconnecting transformer at Penrose   | Auckland             | February 2010      | Completed |
| <i>Huntly-Ohinewai-2 220 kV limiting components</i>              | Replace limiting components on the 220 kV Huntly-Ohinewai-2 circuit  | Waikato              | March 2010         | Completed |
| <i>Wilton (WIL) T8</i>   | New 250 MVA interconnecting transformer at Wilton  | Wellington & HVDC    | May 2010           | Completed |
| <i>Drury Substation</i>  | New substation   | Auckland             | May 2010           | Completed |
| <i>Stratford Peaking plant (SFD) connection</i>                  | New 220 kV connection to 220 kV Stratford bus to allow connection of Stratford Peaking units   | Taranaki             | June 2010          | Completed |

| Asset   | Committed Upgrades   | Region               | Commissioning Date | Status        |
|---|--|----------------------|--------------------|---------------|
| <i>Mangamaire – Woodville 110 kV circuits</i>                                 | Replace conductor – rating increases from 42/51 MVA to 93/113 MVA per circuit.   | Wellington & HVDC    | July 2010          | In progress   |
| <i>Otahuhu Capacitors 200 Mvar</i>  | 2x 100 Mvar Capacitors at Otahuhu  | Auckland             | July 2010          | In progress   |
| <i>Otahuhu Diversity Project</i>  | New 220 kV substation busbar   | Auckland             | July 2010          | In progress   |
| <i>Marsden (MDN) T5 &amp; T6 220/110/11 kV Interconnecting Transformer(s)</i> | Replace existing transformers at Marsden with two new interconnecting transformers [Marsden substation Redevelopment- stage 1 include bus coupler and protection scheme]         | Northland            | December 2010      | In progress   |
| <i>Henderson-Otahuhu 220 kV limiting components</i>                           | Replace limiting components on the 220 kV Henderson - Otahuhu circuit, rating increases to 938/984 MVA   | Northland & Auckland | December 2010      | In progress   |
| <i>Otahuhu-Whakamaru-C</i>  | Thermal upgrade of the Ohinewai-Whakamaru section of the 220 kV Otahuhu-Whakamaru C line [NIGUP]   | Auckland             | July 2011          | Committed     |
| <i>Henderson - Huapai 220 kV limiting components</i>                          | Replace limiting components on the 220 kV Henderson - Huapai circuit, rating increases to 666/740 MVA  | Northland            | July 2011          | Committed     |
| <i>Mangamaire – Masterton 110 kV circuits</i>                                 | Replace conductor – rating increases from 42/51 MVA to 93/113 MVA per circuit.   | Wellington & HVDC    | July 2011          | Committed     |
| <i>Henderson Interconnecting Transformers</i>                                 | Henderson Interconnecting Transformers replace limiting components, rating increased from 229 MVA to 254/270 MVA [May be required prior to NAaN refer to 2010 APR section 7.9.5] | Northland            | July 2011          | Not committed |
| <i>Pakuranga (PAK) 220 kV substation</i>                                      | Convert Pakuranga 110 kV substation to 220 kV substation [NIGUP]   | Auckland             | May 2011           | Committed     |
| <i>Pakuranga – Brownhill -Whakamaru North 220 kV circuit</i>                  | New double circuit overhead line from Whakamaru North to Brownhill transition station and underground cable from Brownhill to Pakuranga [NIGUP]                                  | Auckland             | June 2012          | Committed     |
| <i>Pakuranga (PAK) 220 kV substation upgrade</i>                              | Upgrade Pakuranga 220 kV substation to breaker and a half [NIGUP]  | Auckland             | May 2011           | Committed     |
| <i>Otahuhu - Pakuranga 220 kV</i>   | Convert existing Otahuhu - Pakuranga 110 kV circuit to 220 kV [NIGUP]  | Auckland             | May 2011           | Committed     |
| <i>Decommission Pakuranga –Penrose circuit</i>                                | Take Pakuranga – Penrose circuit out of service [NIGUP]  | Auckland             | June 2012          | Committed     |
| <i>Pakuranga Supply Transformers</i>  | Decommission 2 x 110/33 kV Pakuranga transformers and install 3x 220/33 kV 120 MVA transformers  | Auckland             | May 2011           | Committed     |
| <i>Brownhill Transition Station</i>   | New Brownhill Road cable transition station  | Auckland             | June 2012          | Committed     |
| <i>Whakamaru B Substation</i>   | New Whakamaru North substation, extend 220 kV structure at Whakamaru and build a tie line between sites  | Auckland             | June 2012          | Committed     |
| <i>HVDC Pole 3 – Stage 1</i>  | HVDC Pole 3 – Stage 1 – New converter pole to allow transfer of up to 1000 MW. Work includes new converters and 220 kV filters at Haywards.                                      | Wellington & HVDC    | June 2012          | Committed     |
| <i>HVDC Pole 3 – Stage 1 Haywards 110 kV Filters</i>                          | HVDC Pole 3 – Stage 1 – Replacement of 110 kV filters at Haywards  | Wellington & HVDC    | June 2012          | Committed     |

| Asset  | Committed Upgrades  | Region                   | Commissioning Date | Status                                  |
|--|---|--------------------------|--------------------|---|
| <i>HVDC Pole 3 – Stage 1 Haywards synchronous condenser transformers</i> | HVDC Pole 3 – Stage 1 – Replacement of 110/11 kV synchronous condenser transformers at Haywards   | Wellington & HVDC        | June 2012          | Committed                               |
| <i>HVDC Pole 3 – Stage 1 Haywards synchronous condensers</i>             | HVDC Pole 3 – Stage 1 – Refurbishment of synchronous condensers at Haywards   | Wellington & HVDC        | June 2012          | Committed                               |
| <i>Stratford-Hawera-Waverly-Wanganui 110 kV circuit upgrade</i>          | Replace conductor on the 110 kV Stratford-Hawera-Waverly-Wanganui Line  | Taranaki                 | October 2012       | Committed                               |
| <i>Wairakei Ring Project</i>   | New double circuit transmission line connecting Whakamaru-Te Mihi-Wairakei rated at 903/994 MVA   | Central North Island     | June 2013          | Committed                               |
| <i>NAaN Project</i>  | 220 kV underground cable between Pakuranga, Penrose and Albany  | Northland & Auckland     | 2014               | Committed                               |
| <i>HVDC Pole 3 – Stage 2</i>   | HVDC Pole 3 – Stage 2 Addition of a +/- 60 Mvar Statcom to allow HVDC transfer of up to 1,200 MW  | Wellington & HVDC        | 2014               | Committed                               |
| <b>South Island</b>  |   |                          |                    |   |
| <i>Cromwell (CML) T8</i>   | Install a new 150/150/50 kV, 220/110/33 kV interconnecting Transformer T8 and parallel the existing T7 & T5 transformers as T5A & T5B   | Otago                    | March 2009         | Completed                               |
| <i>New GXP Bells Pond</i>  | New 20 MVA 110 kV GXP on OAM-STU-WTK-2 circuit.   | Otago                    | August 2009        | Completed                               |
| <i>Naseby Transformer Uprating</i>                                       | Uprate Naseby 220/33 kV supply transformers T1 & T2 to 40 MVA   | Otago                    | September 2009     | Completed                               |
| <i>New SVC at Islington</i>  | New SVC at Islington (SVC9) +150/-75 Mvar   | Canterbury               | October 2009       | Completed                               |
| <i>Islington 220 kV 5th Bus Section</i>                                  | Install an additional bus coupler circuit breaker on the Islington 220 kV bus   | Canterbury               | December 2009      | Completed                               |
| <i>New Statcom at Kikiwa</i>   | New Statcom at Kikiwa (ST2a & ST2b) +/- 40 Mvar   | Canterbury               | January 2010       | Completed                               |
| <i>Hokitika 11 kV Capacitors</i>   | 14 Mvar, 11 kV capacitors at Hokitika substation [West Coast 110 kV Transmission Security]  | West Coast               | July 2010          | In progress                             |
| <i>Ashburton (ASB) 220/66 kV Transformer</i>                             | Install a second 220/66 kV transformer at Ashburton   | Canterbury               | September 2010     | Committed                               |
| <i>Islington RPC</i>   | Islington RPC   | Canterbury               | December 2010      | In progress                             |
| <i>Dobson (DOB) T11 Interconnecting Transformer</i>                      | Install a 2nd 110/66 kV Interconnecting transformer at Dobson [West Coast 110 kV Transmission Security] Will be operational following the commissioning of the new DOB-RFN 110 kV circuit | West Coast               | July 2010          | Completed; Operational in November 2011 |
| <i>New Dobson-Reefton 110 kV circuit</i>                                 | Extend the 110 kV IGH-RFN 2 circuit to new Dobson interconnecting transformer   | West Coast               | November 2011      | Committed                               |
| <i>HVDC Pole 3 – Stage 1</i>   | HVDC Pole 3 – Stage 1 – New converter pole to allow transfer of up to 1000 MW. Work includes new converters and 220 kV filters at Benmore.  | Otago & Southland & HVDC | June 2012          | Committed                               |

## 5. HVDC CAPACITY

### 5.1 2011 HVDC OPERATION – SUMMER & WINTER

Half of the original Pole 1 was decommissioned in December 2009.

The remaining half of Pole 1 is available under the limited conditions of normal operation, in response to Grid Emergencies, and for testing. The conditions include north transfer between 130 MW and 200 MW, with automatic controls unavailable (except frequency modulation). Other conditions include a limit on the number of starts, minimum operating time per start and cumulative operating time. When Pole 1 is not operating, HVDC bipole operation is not available. Without bipole operation, the HVDC is in monopole operation, which results in:

- reduced HVDC capacity (one pole rather than two poles in operation);
- increased reserve cover from generation and load required for a Pole trip, and
- ground (sea/earth) return current.

The nominal rating of HVDC Pole 2 is 560 MW, with a continuous overload of 700 MW, which is the maximum possible transfer with only HVDC Pole 2 in service. However, the normal link transfer is dependent on the reserve cover available.

In bipole operation for the failure of one pole, the remaining pole can increase its power transfer, which provides some self cover. This could be partial or full load cover depending on the pre-fault power flow of the remaining pole. There is no self cover possible in a monopolar operation with only HVDC Pole 2 available in service. Also, a planned or unplanned outage under monopolar operation will decouple the two islands and the two markets reducing the generation available to both islands and introducing a price separation.

### 5.2 2012-2013 HVDC OPERATION – SUMMER & WINTER

The project to replace HVDC Pole 1 is called the New Zealand Inter Island HVDC Pole 3 Project (abbreviated to P3 Project). The new thyristor converter based HVDC converter pole will have a nominal power rating of 700 MW.

With a 700 MW converter and with the three existing cables, it is possible to operate the link as a balanced 500/500 MW bipole or as an unbalanced bipole with 700/500 MW (on HVDC Pole 3/Pole 2). This provides a convenient way to stage a capacity increase from a 1000 MW link (Stage 1) to 1200 MW link (Stage 2). The indicative commissioning date of stage 1 and stage 2 is 2012 and 2014, respectively.

A preliminary P3 Project schedule illustrating transition from HVDC Pole 1/Pole 2 operation to HVDC Pole 3/Pole 2 operation and an indicative high level programme for HVDC Pole 3 Synchronous Condenser Refurbishment Project are shown in Table 5-1 and Table 5-2, respectively, as at 2<sup>nd</sup> of July 2010.

Table 5-1 2011-2013 HVDC Project Schedule and Transfer Capability

| Target Date    | HVDC Operation  | Pole Transfer Capability | Bipole Transfer Capacity |
|----------------|---|--------------------------|--------------------------|
| January 2011   | Pole 1 1 x 500 MW cable<br>Pole 2 2 x 500 MW cable                                      | 200 MW<br>700 MW         | 900 MW                   |
| November 2011  | Pole 1<br>Pole 2 1 x 500 MW cable<br>Pole 3<br>(Pole 1 decommission)                    | 500 MW                   | 500 MW                   |
| April 2012     | Pole 2 1 x 500 MW cable<br>Pole 3 2 x 500 MW cable<br>(Pole 3 operational for dispatch) | 500 MW<br>700 MW         | 1000 MW                  |
| September 2012 | Pole 2<br>Pole 3 2 x 500 MW cable<br>(Controls replacement)                             | 700 MW                   | 700 MW                   |
| December 2012  | Pole 2 1 x 500 MW cable<br>Pole 3 2 x 500 MW cable                                      | 500 MW<br>700 MW         | 1000 MW                  |
| November 2013  | Pole 2 1 x 500 MW cable<br>Pole 3 2 x 500 MW cable<br>(STATCOM in service)              | 500 MW<br>700 MW         | 1200 MW                  |

Table 5-2 2011-2013 Pole 3 Synchronous Condenser Refurbishment Project

| Refurbishment | Target Date  |
|---------------|--------------|
| C7            | Jan-Apr 2011 |
| C8            | May-Jul 2011 |
| C2            | Jun-Aug 2011 |
| C9            | Jan-Mar 2012 |
| C10           | Apr-Jun 2012 |
| C3            | Jul-Sep 2012 |
| C4            | Mar-May 2013 |

### 5.3 SUMMARY OF HVDC CAPABILITY

The maximum HVDC capacity for the three year period is shown in Table 5-3.

*Table 5-3 Maximum HVDC Transfer Capability*

| HVDC Transfer (MW)    | 2011   |        | 2012   |          | 2013   |        |
|-----------------------|--------|--------|--------|----------|--------|--------|
|                       | summer | winter | summer | winter   | summer | winter |
| <i>North Transfer</i> | 900*   | 900*   | 500    | 500-1000 | 1000   | 1000   |
| <i>South Transfer</i> | 666    | 666    | 500    | 1000     | 1000   | 1000   |

\* HVDC Pole 2 (700 MW) and HVDC Pole 1 (130 MW-200 MW), the maximum HVDC capacity is dependent on the reserve cover available in the system at the time of dispatch.

For study purposes the transfer levels given in Table 5-4 have been assumed.

*Table 5-4 HVDC Transfer assumed for SSF Studies*

| HVDC Transfer (MW)    | 2011   |        | 2012   |          | 2013    |         |
|-----------------------|--------|--------|--------|----------|---------|---------|
|                       | summer | winter | summer | winter   | summer  | winter  |
| <i>North Transfer</i> | 600    | 600    | 500    | 500-1000 | 1000    | 1000    |
| <i>South Transfer</i> | 300    | 300    | 300    | 300-400  | 400-500 | 400-500 |

## 6. DEMAND FORECAST

### 6.1 REGIONAL PEAK DEMAND FORECAST

The demand forecast is prepared by the Electricity Commission and is published in the Statement of Opportunities (SOO). The revised version of demand forecast and the associated review documents have been published as part of the Grid Planning Assumptions (GPA)<sup>2</sup>. The demand forecast comprises of information on future electricity demand at national, regional and grid exit point level. Information in Table 6-1 is used in December 2010 System Security Forecast (SSF) to assess the capability of New Zealand Power System in meeting the forecasted demand.

The demand projections are based on historic trends. Expected and prudent forecasts are used. The expected forecast considers the average trends in demand growth. The prudent forecast is based on the expected forecast but is a higher forecast allowing for the variability of demand in any particular year from the average (for example, higher demand resulting from a typical cold snap). A 10% probability of exceedance criterion (P10) is used to predict prudent demand forecast.

The maximum demand figures utilised in the report analysis are the After Diversity Maximum Demand (ADMD). These forecast figures incorporate the natural diversity of point of supply loads with peak periods not occurring simultaneously.

Table 6-1 List of Expected and Prudent Demand Forecast

| Name                        | Expected or Prudent | Summer    |           |           |              | Winter    |           |           |              |
|-----------------------------|---------------------|-----------|-----------|-----------|--------------|-----------|-----------|-----------|--------------|
|                             |                     | 2011 (MW) | 2012 (MW) | 2013 (MW) | Power Factor | 2011 (MW) | 2012 (MW) | 2013 (MW) | Power Factor |
| <b><i>NORTH ISLAND</i></b>  |                     |           |           |           |              |           |           |           |              |
| <i>Northland</i>            | Expected            | 742       | 765       | 786       | 0.99         | 911       | 940       | 966       | 0.98         |
|                             | Prudent             | 771       | 795       | 827       | 0.99         | 941       | 972       | 1011      | 0.98         |
| <i>Auckland</i>             | Expected            | 1237      | 1275      | 1312      | 0.99         | 1460      | 1504      | 1548      | 0.99         |
|                             | Prudent             | 1311      | 1356      | 1400      | 0.99         | 1547      | 1601      | 1652      | 0.99         |
| <i>Waikato</i>              | Expected            | 337       | 343       | 350       | 0.99         | 367       | 374       | 381       | 0.99         |
|                             | Prudent             | 353       | 361       | 371       | 0.99         | 385       | 394       | 405       | 0.99         |
| <i>Bay of Plenty</i>        | Expected            | 515       | 524       | 534       | 0.98         | 535       | 545       | 555       | 0.98         |
|                             | Prudent             | 538       | 551       | 564       | 0.98         | 560       | 573       | 587       | 0.98         |
| <i>Hawkes Bay</i>           | Expected            | 259       | 263       | 269       | 0.98         | 279       | 284       | 290       | 0.99         |
|                             | Prudent             | 268       | 276       | 284       | 0.98         | 289       | 297       | 306       | 0.99         |
| <i>Central North Island</i> | Expected            | 266       | 272       | 278       | 0.97         | 338       | 346       | 354       | 0.97         |
|                             | Prudent             | 277       | 286       | 294       | 0.97         | 352       | 363       | 374       | 0.97         |

<sup>2</sup> <http://www.ea.govt.nz/our-work/consultations/modelling/2008-grid-planning-assumptions/>

| Name                         | Expected<br>or<br>Prudent | Summer |      |      |      | Winter |      |      |      |
|------------------------------|---------------------------|--------|------|------|------|--------|------|------|------|
| <i>Taranaki</i>              | Expected                  | 208    | 211  | 214  | 0.98 | 224    | 227  | 231  | 0.98 |
|                              | Prudent                   | 217    | 220  | 226  | 0.98 | 234    | 238  | 244  | 0.98 |
| <i>Wellington</i>            | Expected                  | 605    | 619  | 633  | 0.98 | 721    | 738  | 755  | 0.98 |
|                              | Prudent                   | 629    | 650  | 668  | 0.98 | 750    | 775  | 796  | 0.98 |
| <b>SOUTH ISLAND</b>          |                           |        |      |      |      |        |      |      |      |
| <i>Nelson-Marlborough</i>    | Expected                  | 249    | 263  | 269  | 0.99 | 277    | 292  | 299  | 0.99 |
|                              | Prudent                   | 258    | 274  | 283  | 0.99 | 287    | 304  | 314  | 0.99 |
| <i>West Coast</i>            | Expected                  | 51     | 58   | 60   | 0.99 | 46     | 53   | 55   | 0.99 |
|                              | Prudent                   | 52     | 61   | 63   | 0.99 | 48     | 56   | 58   | 0.99 |
| <i>Canterbury</i>            | Expected                  | 784    | 805  | 827  | 0.99 | 878    | 901  | 925  | 0.99 |
|                              | Prudent                   | 815    | 843  | 869  | 0.99 | 912    | 943  | 971  | 0.99 |
| <i>Otago &amp; Southland</i> | Expected                  | 1102   | 1116 | 1127 | 0.97 | 1138   | 1152 | 1164 | 0.97 |
|                              | Prudent                   | 1141   | 1164 | 1184 | 0.97 | 1178   | 1203 | 1225 | 0.97 |

The SSF uses regional boundaries which are aligned to current power system capability limits. These regional boundaries are sometimes different to those used in other publications resulting in differences in regional load forecasts between the SSF and the other publications.

## 7. GENERATION

### 7.1 GENERATION

Hydro-power generation currently represents approximately 54% of the total installed generation capacity in New Zealand. The remainder is mainly thermal and co-generation, with geothermal generation contributing around 9%. A list of generators is contained in Table 7-1 below.

The SSF studies assume that all existing generating stations and those committed as at 2<sup>nd</sup> July 2010 will continue to operate according to their stated capability until the end of the study period in 2013. It is also assumed that there is sufficient fuel available for all existing generating stations and those committed for the three year period. The reactive power output available from the generators is assumed to be as per the generator capability charts supplied to the System Operator.

Asset Capability Statement information provided by asset owners to the System Operator is kept confidential in accordance with Part 8, Schedule 8.3, Technical Code A clause 3 (2) of the 'Code'. Information concerning the capability of individual generating units has not been published in this SSF unless the information is already in the public domain.

Table 7-1 List of Asset Capability Statement - Generation and Assumed Dispatch

| Name                                       | Type                    | Capacity (MW) | Assumed 2012 Dispatch (MW) * | Region               |
|--|-------------------------|---------------|------------------------------|----------------------|
| <b>NORTH ISLAND</b>                        |                         |               |                              |                      |
| <i>Aniwhenua</i>                           | Hydro                   | 20            | 20                           | Bay of Plenty        |
| <i>Arapuni – Waikato</i>                   | Hydro                   | 176           | 176                          | Waikato              |
| <i>Aratiatia – Waikato</i>                 | Hydro                   | 84            | 78                           | Central North Island |
| <i>Atiamuri – Waikato</i>                  | Hydro                   | 80            | 72                           | Bay of Plenty        |
| <i>Glenbrook – G1&amp; G2</i>              | Cogeneration - embedded | 38            | 0                            | Auckland             |
| <i>Glenbrook – G3</i>                      | Cogeneration            | 74            | 47                           | Auckland             |
| <i>Huntly (units 1-4)</i>                  | Thermal                 | 1000          | 1000                         | Auckland             |
| <i>Huntly unit 5</i>                       | Gas - CCGT              | 400           | 394                          | Auckland             |
| <i>Huntly P40 (unit 6)</i>                 | Gas - OCGT              | 50            | 40                           | Auckland             |
| <i>KA24 - Kawerau</i>                      | Geothermal              | 10            | 10                           | Bay of Plenty        |
| <i>Kaitawa – Waikaremoana Hydro Scheme</i> | Hydro                   | 36            | 30                           | Hawkes Bay           |
| <i>Karapiro – Waikato</i>                  | Hydro                   | 96            | 90                           | Waikato              |
| <i>Kinleith</i>                            | Cogeneration            | 40            | 29                           | Bay of Plenty        |
| <i>Kapuni</i>                              | Cogeneration            | 22            | 20                           | Taranaki             |
| <i>Kawerau</i>                             | Geothermal              | 110           | 100                          | Bay of Plenty        |
| <i>Lloyd Mandeno – Kaimai Hydro Scheme</i> | Hydro – embedded        | 22            | 16                           | Bay of Plenty        |

| Name   | Type                  | Capacity (MW) | Assumed 2012 Dispatch (MW)* | Region               |
|--|-----------------------|---------------|-----------------------------|----------------------|
| <i>Lower Mangapapa – Kaimai Hydro Scheme</i> | Hydro – embedded      | 6             | 5.6                         | Bay of Plenty        |
| <i>Mokai</i>                                 | Geothermal            | 124           | 104.5                       | Central North Island |
| <i>Mangahao</i>                              | Hydro                 | 37            | 35                          | Central North Island |
| <i>Maraetai A – Waikato</i>                  | Hydro                 | 180           | 180                         | Central North Island |
| <i>Maraetai B – Waikato</i>                  | Hydro                 | 180           | 180                         | Central North Island |
| <i>Matahina</i>                              | Hydro                 | 72            | 70                          | Bay of Plenty        |
| <i>Nga Awa Purua</i>                         | Geothermal            | 132           | 130                         | Central North Island |
| <i>Ngawha 1</i>                              | Geothermal            | 8             | 7                           | Northland            |
| <i>Ngawha Power Station</i>                  | Geothermal            | 20            | 12                          | Northland            |
| <i>Ohaaki</i>                                | Geothermal            | 91            | 90                          | Central North Island |
| <i>Ohakuri – Waikato</i>                     | Hydro                 | 112           | 100                         | Bay of Plenty        |
| <i>Otahuhu B</i>                             | CCGT                  | 372           | 370                         | Auckland             |
| <i>Patea - Hawera</i>                        | Hydro                 | 31            | 28.5                        | Taranaki             |
| <i>Piripaua – Waikaremoana Hydro Scheme</i>  | Hydro                 | 40            | 38                          | Hawkes Bay           |
| <i>Poihipi</i>                               | Geothermal            | 55            | 48                          | Central North Island |
| <i>Rangipo – Tongariro</i>                   | Hydro                 | 120           | 120                         | Central North Island |
| <i>Rotokawa</i>                              | Geothermal - embedded | 37.5          | 30.4                        | Central North Island |
| <i>Ruahiri - Kaimai Hydro Scheme</i>         | Hydro - embedded      | 20            | 20                          | Bay of Plenty        |
| <i>Southdown</i>                             | Cogeneration          | 112           | 108                         | Northland            |
| <i>Southdown unit 5</i>                      | CCGT                  | 60            | 57                          | Northland            |
| <i>Stratford Peaking Plant</i>               | Gas                   | 200           | 200                         | Taranaki             |
| <i>Taranaki Combined Cycle</i>               | CCGT                  | 379           | 360                         | Taranaki             |
| <i>Tararua 1 &amp; 2</i>                     | Wind - embedded       | 68            | 13.6                        | Central North Island |
| <i>Tararua 3</i>                             | Wind                  | 90            | 18                          | Wellington           |
| <i>Tasman Mill - Kawerau</i>                 | Geothermal            | 37            | 30                          | Bay of Plenty        |
| <i>Tauhara - Centennial Drive Binary</i>     | Geothermal            | 23            | 21                          | Central North Island |
| <i>Te Apiti</i>                              | Wind                  | 90            | 18                          | Central North Island |
| <i>Te Rapa – Te Kowhai</i>                   | Cogeneration          | 42            | 40                          | Central North Island |
| <i>Te Rere Hau Stage 1-3</i>                 | Wind                  | 34            | 6.8                         | Wellington           |
| <i>Tokaanu – Tongariro</i>                   | Hydro                 | 240           | 240                         | Central North Island |
| <i>Tuai – Waikaremoana Hydro Scheme</i>      | Hydro                 | 67            | 50                          | Hawkes Bay           |
| <i>Waipapa – Waikato</i>                     | Hydro                 | 51            | 48                          | Central North Island |

| Name                                     | Type                   | Capacity (MW) | Assumed 2012 Dispatch (MW)* | Region               |
|--|------------------------|---------------|-----------------------------|----------------------|
| <i>Wairakei</i>                          | Geothermal             | 174           | 167                         | Central North Island |
| <i>West Wind</i>                         | Wind                   | 142           | 28.4                        | Wellington           |
| <i>Whakamaru – Waikato</i>               | Hydro                  | 100           | 100                         | Central North Island |
| <i>Whareroa – aka Kiwi Dairy, Hawera</i> | Cogeneration           | 69            | 65                          | Taranaki             |
| <i>Wheao</i>                             | Hydro                  | 25            | 11                          | Bay of Plenty        |
| <i>Whirinaki</i>                         | Gas Turbine            | 156           | 0                           | Hawkes Bay           |
| <i>Whirinaki – Pan Pac</i>               | Gas Turbine - embedded | 13.4          | 13.4                        | Hawkes Bay           |
| <b>SOUTH ISLAND</b>                      |                        |               |                             |                      |
| <i>Argyle &amp; Wairua</i>               | Hydro                  | 11            | 8                           | Nelson-Marlborough   |
| <i>Aviemore – Waitaki</i>                | Hydro                  | 220           | 200                         | Otago & Southland    |
| <i>Benmore – Waitaki</i>                 | Hydro                  | 540           | 526                         | Otago & Southland    |
| <i>Clyde – Clutha</i>                    | Hydro                  | 432           | 432                         | Otago & Southland    |
| <i>Cobb</i>                              | Hydro                  | 32            | 27                          | Nelson-Marlborough   |
| <i>Coleridge</i>                         | Hydro                  | 45            | 39                          | West Coast           |
| <i>Kumara/Dilmans</i>                    | Hydro                  | 10            | 6                           | West Coast           |
| <i>Manapouri</i>                         | Hydro                  | 720           | 720                         | Otago & Southland    |
| <i>Ohau A – Waitaki</i>                  | Hydro                  | 264           | 260                         | Otago & Southland    |
| <i>Ohau B – Waitaki</i>                  | Hydro                  | 212           | 200                         | Otago & Southland    |
| <i>Ohau C – Waitaki</i>                  | Hydro                  | 212           | 200                         | Otago & Southland    |
| <i>Roxburgh – Clutha</i>                 | Hydro                  | 320           | 312                         | Otago & Southland    |
| <i>Tekapo A – Waitaki</i>                | Hydro                  | 25            | 20                          | Canterbury           |
| <i>Tekapo B – Waitaki</i>                | Hydro                  | 160           | 148                         | Canterbury           |
| <i>Waipori</i>                           | Hydro                  | 94            | 60                          | Otago & Southland    |
| <i>Waitaki – Waitaki</i>                 | Hydro                  | 105           | 84                          | Otago & Southland    |
| <i>White Hill</i>                        | Wind - embedded        | 40            | 0                           | Otago & Southland    |

**Note:** \* Assumed Generation dispatch provided assumes 600 MW HVDC North transfer.

## 7.2 SLACK BUS / GENERATION & HVDC TRANSFER

It is necessary when undertaking power system studies to assign a slack bus or slack generation (Table 7-2).

*Table 7-2 List of Slack Bus Selection*

| Region                       | Slack               |
|------------------------------|---------------------|
| <b>NORTH ISLAND</b>          |                     |
| <i>Northland</i>             | Stratford/Huntly    |
| <i>Auckland</i>              | Stratford/Whakamaru |
| <i>Waikato</i>               | Stratford/Huntly    |
| <i>Bay of Plenty</i>         | Stratford/Huntly    |
| <i>Hawkes Bay</i>            | Stratford/Huntly    |
| <i>Central North Island</i>  | Otahuhu B           |
| <i>Taranaki</i>              | Huntly              |
| <i>Wellington &amp; HVDC</i> | Huntly              |
| <b>SOUTH ISLAND</b>          |                     |
| <i>Nelson-Marlborough</i>    | Clyde               |
| <i>West Coast</i>            | Clyde               |
| <i>Canterbury</i>            | Clyde               |
| <i>Otago &amp; Southland</i> | Ohau A              |

## 8. REACTIVE POWER SOURCES

The following sections list all the system capacitors, reactors, synchronous condensers, Static Var Compensators and Statcoms connected to the grid as at 2<sup>nd</sup> July 2010.

The network reactive power sources assumed in the analysis are listed in the appendix section. The total reactive power available from the network capacitors including the HVDC filter capacitors is 2926.5 Mvar.

The total reactive power available from the installed network Static Var Compensators (SVCs) and synchronous condensers is -698/+1045 Mvar. The Marsden synchronous condenser is assumed to be unavailable.

### 8.1 CAPACITORS

Table 8-1 List of Static Capacitors

| Bus  | No. x Size (Mvar) | Total (Mvar) | Assumed Dispatch (Mvar) | Automatically switched (RPC) |
|--|-------------------|--------------|-------------------------|------------------------------|
| <b>North Island</b>                          |                   |              |                         |                              |
| <i>Albany 11 kV - T4 - Decommissioned</i>    | 2 x 30            | 60           | 0                       |                              |
| <i>Albany 110 kV</i>                         | 1 x 50            | 50           | 50                      |                              |
| <i>Albany 220 kV</i>                         | 1 x 100           | 100          | 100                     |                              |
| <i>Bombay 110 kV</i>                         | 1 x 50            | 50           | 50                      |                              |
| <i>Gisborne 110 kV</i>                       | 1 x 12            | 12           | 12                      | Yes (110 kV +/- 5 %)         |
| <i>Haywards 110 kV (F1 &amp; F2)</i>         | 2 x 47.5          | 95           | 95                      |                              |
| <i>Haywards 220 kV (F3 &amp; F4)</i>         | 2 x 60 + 2 x 45   | 210          | 210                     |                              |
| <i>Henderson 11 kV - T5 - Decommissioned</i> | 2 x 30            | 60           | 0                       |                              |
| <i>Henderson 220 kV</i>                      | 1 x 75            | 75           | 75                      |                              |
| <i>Hepburn Rd 110 kV - C11</i>               | 1 x 50            | 50           | 50                      |                              |
| <i>Hepburn Rd 110 kV - C12</i>               | 1 x 50            | 50           | 50                      |                              |
| <i>Hepburn Rd 110 kV - C13</i>               | 1 x 50            | 50           | 50                      |                              |
| <i>Kaikohe 11 kV</i>                         | 4 x 5             | 20           | 20                      | Yes (110 kV +/- 5 %)         |
| <i>Kaitaia 33 kV</i>                         | 3.2, 6.4 & 12.8   | 22.4         | 6.4                     |                              |
| <i>Mount Maunganui 110 kV</i>                | 1 x 25            | 25           | 24                      |                              |
| <i>Ongarue 33 kV</i>                         | 1 x 2.5           | 2.5          | 2.5                     |                              |
| <i>Otahuhu 11 kV - T4 - Decommissioned</i>   | 2 x 30            | 60           | 0                       |                              |
| <i>Otahuhu 11 kV - T2 - Decommissioned</i>   | 1 x 30            | 30           | 0                       |                              |
| <i>Otahuhu 110 kV - C11</i>                  | 1 x 50            | 50           | 50                      |                              |
| <i>Otahuhu 110 kV - C12</i>                  | 1 x 50            | 50           | 50                      |                              |
| <i>Otahuhu 220 kV - C29</i>                  | 1x 100            | 100          | 100                     |                              |
| <i>Otahuhu 220 kV</i>                        | 2x 100            | 200          | 200                     |                              |
| <i>Penrose 220 kV- C1</i>                    | 1 x 75            | 75           | 75                      |                              |
| <i>Penrose 110 kV- C11</i>                   | 1 x 50            | 50           | 50                      |                              |
| <i>Penrose 110 kV- C12</i>                   | 1 x 50            | 50           | 50                      |                              |

| Bus                                    | No. x Size (Mvar)  | Total (Mvar)  | Assumed Dispatch (Mvar) | Automatically switched (RPC) |
|--|--------------------|---------------|-------------------------|------------------------------|
| Penrose 110 kV- C13                    | 1 x 50             | 50            | 50                      |                              |
| Penrose 110 kV- C14                    | 1 x 50             | 50            | 50                      |                              |
| Tauranga 110 kV                        | 1 x 25             | 25            | 24                      |                              |
| Wairau Road 33 kV 3                    | 2 x 18             | 36            | 36                      | Yes (33 kV +/- 2%)           |
| <b>South Island</b>                    |                    |               |                         |                              |
| Benmore 33 kV - T2 (F1)                | 1 x 51             | 51            | 51                      |                              |
| Benmore 33 kV - T5 (F2)                | 1 x 51             | 51            | 51                      |                              |
| Benmore 220 kV (F3 & F4)               | 2 x 50.5, 2 x 36.2 | 173.4         | 173.4                   |                              |
| Blenheim 33 kV (C1, C2, C3 & C4)       | 4 x 5.10           | 20            | 10                      | Yes (33 kV +/- 2%)           |
| Bromley 11 kV (C5A & C6A)              | 2 x 30             | 60            | 0                       | Yes (11 kV -5% to +3%)       |
| Brydone 11 kV (C1, C2, C4 & C5)        | 4 x 5.15           | 21            | 21                      | Yes (110 kV +1% to +4%)      |
| Greymouth 11 kV                        | 4, 2 & 1           | 7             | 0                       | Yes (66 kV 0% to +2.5%)      |
| Hokitika 11 kV                         | 1, 1.4 & 2.8       | 5.2           | 1                       | Yes (66 kV +/- 5%)           |
| Hokitika 11 kV                         | 2, 4 & 8           | 14            | 0                       | Yes (66 kV +/- 5%)           |
| Islington 66 kV (C14, C15 & C16)       | 3 x 37             | 111           | 74                      | Yes (66 kV +2% to +4%)       |
| Islington 220 kV (C21, C22, C25 & C26) | 4 x 60             | 240           | 240                     |                              |
| Islington 220 kV (C27)                 | 1 x75              | 75            | 0                       |                              |
| North Makarewa 220 kV (C1 & C3)        | 2 x 50             | 100           | 100                     |                              |
| Stoke 11 kV T7                         | 4 x 5              | 20            | 15                      | Yes (110 kV +0.5% to +4.5%)  |
| Stoke 33 kV                            | 4 x 10             | 40            | 20                      | Yes (33 kV +/- 2%)           |
| Southbrook 66 kV                       | 1 x 33             | 33            | 33                      |                              |
| Tiwai (HF1 & HF2)                      | 2 x 26             | 52            | 52                      | Yes (220 kV +1.5% to +3.5%)  |
| Tiwai (HF3)                            | 1 x 45             | 45            | 0                       | Yes (220 kV +1.5% to +3.5%)  |
| Tiwai (HF4)                            | 1 x 30             | 30            | 0                       | Yes (220 kV +1.5% to +3.5%)  |
| Tiwai (HF11 & HF21)                    | 2 x 10             | 20            | 20                      | Yes (220 kV +1.5% to +3.5%)  |
| <b>TOTAL (NZ)</b>                      |                    | <b>2926.5</b> | <b>2921.3</b>           |                              |

## 8.2 REACTORS

Table 8-2 List of Reactors

| Bus                     | No. x Size (Mvar) | Total (Mvar) | Assumed Dispatch (Mvar) | Automatically switched (RPC) |
|-------------------------|-------------------|--------------|-------------------------|------------------------------|
| <b>North Island</b>     |                   |              |                         |                              |
| Haywards 11 kV - R1     | 1 x 40            | 40           | 0                       |                              |
| Haywards 11 kV - R5     | 1 x 40            | 40           | 0                       |                              |
| <b>South Island</b>     |                   |              |                         |                              |
| Bromley 11 kV - T5 - R5 | 1x 30             | 30           | 0                       |                              |
| Stoke 11 kV - T7 - R7   | 2 x 5             | 10           | 0                       | Yes (110 kV +0.5% to +4.5%)  |

<sup>3</sup> Owned and operated by Vector Limited.

### 8.3 SYNCHRONOUS CONDENSERS

Table 8-3 List of Synchronous Condensers

| Bus                               | No. x Size (Mvar) | Total (Mvar) | Automatically switched (RPC)             |
|-----------------------------------|-------------------|--------------|--|
| <b>North Island</b>               |                   |              |  |
| Haywards 11 kV – C1               | 1x -30/+50        | -30/+50      | HAY 220 Vref 1.035 p.u.                  |
| Haywards 11 kV – C2               | 1x -30/+60        | -30/+60      | HAY 220 Vref 1.035 p.u.                  |
| Haywards 11 kV – C3 & C4          | 2x -20/+30        | -40/+60      | HAY 220 Vref 1.035 p.u.                  |
| Haywards 11 kV – C7, C8, C9 & C10 | 4x -40/+65        | -160/+260    | Pole 1A/1B 98.5 kV Vref 0.995 p.u.       |
| Otahuhu 110_PS2 - GT4, GT5, GT6   | 3x -29/+33        | -87/+99      | OTA 110-1 Vref 1.034 p.u. (or 1.02 p.u.) |
| Otahuhu 110_PS1 - GT1, GT2        | 2 x -28/+53       | -56/+106     | OTA 110-2 Vref 1.034 p.u. (or 1.02 p.u.) |
| <b>South Island</b>               |                   |              |  |
| Islington - T6 LV (C4 & C5)       | 2x -15/+30        | -30/+60      | 11 kV local Vref 1.025 p.u.              |

### 8.4 STATIC VAR COMPENSATORS (SVCs) & STATCOMS

Table 8-4 List of Static Var Compensators and STATCOMS

| Bus                     | No. x Size (Mvar) | Total (Mvar) | Automatically switched (RPC) |
|-------------------------|-------------------|--------------|------------------------------|
| <b>North Island</b>     |                   |              |                              |
| Albany 220 kV           | 1 x -100/+100     | -100/+100    | 220 kV Vref 1.025 p.u.       |
| <b>South Island</b>     |                   |              |                              |
| Islington 220 kV – SVC9 | 1 x -75/150       | -75/+150     | 220 kV Vref 1.03 p.u.        |
| Islington T3 LV – SVC3  | 1 x -50/60        | -50/+60      | 11 kV Vref 1.025 p.u.        |
| Kikawa 220 kV – Statcom | 1 x -40/40        | -40/+40      | 220 kV Vref 1.03 p.u.        |

## 9. OPERATIONAL MEASURES

Power system issues can be mitigated by a variety of operational measures. Some operational measures are put into place pre-event others take effect after the event.

In order to avoid post-event issues following a CE, the System Operator applies security constraints in the Scheduling Pricing and Dispatch Model (SPD) to maintain pre-event operation within stability limits and maintain operation within the stated short term transmission capability as advised by grid owners. The security constraints allow sufficient time after a contingent event for the re-dispatch of generation or load shedding to maintain operation within advised transmission capability.

Other issues can be mitigated by the actions of asset owners. Load management can be used to reduce demand below the power system limit. The use of short term transmission capabilities advised by asset owners allows power system limits to be increased. Grid reconfiguration advised by grid owners may change the power system limit. The operation of special protection schemes (e.g. intertrip schemes and generation runback schemes) advised by asset owners allows for generation or demand reduction following events to ensure that assets remain within stated capability post-event.

The following operational measures can be employed to maintain system security. The measures listed in Table 9-1 are discussed in the following sub-sections:

*Table 9-1 Summary of Operational Measures*

| Operational Measure  | Description   |
|--|---|
| <i>Pre-Contingency Arrangements/Measures</i>                   | Security Constraints<br>Reduced Security<br>Voltage Agreements (WVA, LOA)<br>Load and Generation Agreements   |
| <i>Thermal Ratings</i>   | 24 hour Continuous Ratings<br>Short Term Ratings  |
| <i>Ancillary Services / Operating Reserves</i>                 | Under-Frequency Reserve<br>Over-Frequency Reserve   |
| <i>Automatic Post Event Action / Special Protection Scheme</i> | Automatic inter-tripping & overload protection<br>Planned Load Shedding / Demand Reduction<br>Automatic Under Voltage Load Shedding (AUVLS)<br>Generation Run Back<br>Switching of Reactive Devices |
| <i>Grid Configuration</i>                                      | Temporary Splits<br>Permanent Splits<br>Busbar Section Splits   |
| <i>Hot Standby</i>   | Transformers  |
| <i>Automatic Under Frequency Load Shedding (AUFLS)</i>         | Minimise or control effects of multiple contingencies causing severe system under frequency.<br>Trips island block loads at pre-defined frequency excursions  |
| <i>Emergency Load Shedding / Demand Reduction</i>              | Grid Warning Notices (WRN)<br>Grid Emergency Notices (GEN)<br>Demand Allocation Notices (DAN)   |

## 9.1 PRE-CONTINGENCY ARRANGEMENTS

Following the receipt of transmission asset and generation offers/bids the System Operator will accept offers/bids using a mechanism that ensures system security. In the event that system security requirements are not met due to the unavailability of an asset or assets, the System Operator will apply pre-contingency measures to manage the system security risk. Pre-contingency measures include security constraints; arrangements made with consumers to accept reduced security and/or reduced power quality and load/generator agreements to maintain a specified level of loading or generation during the risk period.

### 9.1.1 SECURITY CONSTRAINTS

Circuit ratings are advised by the Grid Owner and will include summer, winter and shoulder values. They may be determined by the thermal limit of the conductors (conductor type and strain tension) or limitations on circuit components (i.e. protection, CT Secondaries, Circuit Breakers, Disconnectors) to carry current. The lowest value of any of these will set the maximum loading the circuit may be operated at. This value may need to be adjusted to some lower value for security reasons, such adjustments are termed security constraints.

Security Constraints may be applied to manage circuit loading when:

- a circuit is removed from service (typically for planned or unplanned outages);
- to ensure post-event circuit loading does not exceed short term ratings (15 minute off-load times);
- to ensure system stability is maintained following a contingent event;
- to ensure sufficient reactive power is available to maintain voltage levels following a contingent event.

Security constraints are represented within the scheduling and dispatch tools used by the System Operator. Security constraint equations within the scheduling application will manage generation dispatch profile/scenario(s) to maintain power transfers within asset capabilities for the risk period.

#### 9.1.1.1 *15 Minute Off-Load Times*

In order to meet the requirements of the 'Code' and manage circuit loadings within short term ratings, the System Operator ensures that there is sufficient time to take corrective action after an event, with sufficient available standby generation reserves or agreed load management to achieve the requirements. It is generally agreed that sufficient time is 15 minutes. This time is consistent with being able to manage an N-1 event and is based on international practice. It allows time for grid events to be managed by market mechanisms where practicable prior to taking other action. In addition, it allows sufficient time to arrange manual demand curtailment where generation to relieve the post contingency overloading does not exist. Special consideration is made for situations where it is not possible to meet 15 minute off-load times with all equipment in service. Special Protection Schemes are typically utilised in places where this occurs.

### 9.1.2 REDUCED SECURITY

Where loads are fed by a single radial feeder or single supply transformer the loss of a network component will result in loss of supply. In such cases the security of supply to this load does not meet the N-1 criteria and is said to be on N-security. Many customers fed by a single transmission circuit, radial feeder or supply transformer, accept N-security since the investment required to improve the security of supply may be uneconomic. It is possible that customer load may be placed on reduced security during outage or maintenance periods.

### 9.1.3 VOLTAGE AGREEMENTS

If unable to manage voltage to within the AOPO range following a contingent event, without declaring a grid emergency, the System Operator will seek Wider Voltage Agreement (WVA) from the Grid Owner for a wider voltage range. Where a WVA is approved, the new voltage range applies only following a contingency event. Even where a WVA has been granted, the AOPO range is to be observed during normal system operation, including during planned outages. The majority of WVAs are for the South Island 66 kV system, most of which allow voltage to fall to -10%.

The System Operator may also enter into a Local Quality Agreement (LQA) where so requested by the Grid Owner. An LQA will typically apply where the supply voltage is unregulated (i.e. the supply transformer is off-load tap change capable only), and is intended to achieve supply voltages within a range agreed with the connecting parties. As a consequence, the grid voltage will need to be managed to a lesser range than the AOPO range. The Grid Owner's expectation is that the LQA will be observed during normal system operation with no outages; while during outage periods following contingent events, that best endeavours should be made using available reactive support and/or transmission and/or generation to maintain local voltage range.

### 9.1.4 LOAD AND GENERATION AGREEMENTS

A generation availability agreement may be required to satisfy constraint requirements or arranged as a standalone mitigation measure. If generation is not available then load management will be required. Load agreements may be arranged to manage load pre-contingency.

A generation availability agreement means that the requested generation is 'available to be dispatched'. Consideration is also given as to whether there is sufficient fuel available. For outage assessments, wind generation is never considered to be available.

Load Management can involve the management of load at individual substations, across numerous substations or within an entire Grid Zone or Zone. Load management may also involve the movement of loads between substations.

Where widespread load management is required across a Grid Zone or a Zone then the overall load management value is broken down by distributor (which assists Field Services to reach agreement with distributors). Note that in order to meet the load management requirements the network company may move load to another GXP which may create additional problems.

## 9.2 THERMAL RATINGS

The thermal and voltage ratings of each transmission element are based on the equipment specification, international standards, and in some cases age of the component and local meteorological conditions. Normal and contingency (or emergency) ratings are then used to determine operating limits that allow system preparation for either the next contingency or for system restoration. These limits are updated on a regular basis.

All power system components have a normal continuous rating and a set of post-contingency ratings that allow increased loading for defined periods of time. Transpower Grid Owner and System Operator use normal and 24 hour post-contingency ratings for circuits and transformers when evaluating maximum transfer capabilities post-event. In addition System Operator will make use of 15 minute short term off-load ratings available for transmission circuits to manage disturbances. Once the contingency rating has been utilised for the stated time period, the loading on the component must be returned to within the normal continuous rating. In verifying that a 15 minute off-load time exists, consideration is given to:

- Availability and location of standby generation to recover from the associated contingency;
- There being an agreed load management plan where insufficient generation is available to cover the contingency.

The adoption of short term ratings require assurance from the asset owner that accessories and associated protection settings allow the utilisation of short term ratings. Note that where circuit components other than the conductor determine the circuit maximum rating, no additional short term rating is permitted (i.e. the circuit can only be loaded to 100% rating pre and post contingency with no off-load time).

It may not be possible or practical to meet 15 minute off-load times during planned outages. Under these circumstances automatic or manual actions are planned and agreed before proceeding with the outage.

Shorter off-load times may be applied in the following situations listed in Table 9-2.

*Table 9-2 Summary of Shorter Off-Load Times*

| Off-load time (minutes) | Criteria   |
|-------------------------|--|
| 10 to 15                | Customer(s) has provided in writing a plan to shed or shift load. Agreed immediate action will be taken by the network company on request of the System Operator. The ROC will have delegated authority to act on the SO behalf. |
| 5 to 10                 | EMS SCADA is set up manually trip the network company's agreed loads. In response to the SCADA alarm the Security Coordinator manually trips feeders until overloading is eliminated.  |
| 3 to 5                  | EMS SCADA is set up to automatically trip the network company's agreed loads. The Grid Owner installed a hardwired protection grade inter-trip   |

**Note:** All of the above are subject to written sign-off from the Grid Owner.

The traditional "static" thermal current ratings are determined from the maximum permissible temperature of the conductors to avoid excessive sag or long-term annealing of the conductors. The

calculation does not consider environmental factors that may cool the conductor therefore it is recognised that these static ratings are typically conservative and at times result in under-utilisation of circuits.

Until recently, Transpower applied either summer or winter thermal ratings to network plant. From the 15<sup>th</sup> of March 2010 a new “shoulder rating” limit was introduced. All transmission circuits will use the shoulder rating during the shoulder season. Note that the shoulder rating applies to transmission circuits only. The introduction of a shoulder rating allows additional transfer capacity during the shoulder period.

The ratings are based on the Transpower standard circuit rating methodology, which assumes an ambient temperature 30 °C during the summer period, 25 °C during the shoulder period and 20 °C during the winter period. The day-time and night-time ratings to be applied for the different times of the year are given in Table 9-3.

*Table 9-3 Summary of Thermal Ratings*

| Name            | From Date, Time     | To Date, Time       | Day Rating<br>(07:00-20:59) | Night Rating<br>(21:00-06:59) |
|-----------------|---------------------|---------------------|-----------------------------|-------------------------------|
| <i>Summer</i>   | 1st December, 07:00 | 15th March, 06:59   | Summer (30 °C)              | Winter (20 °C)                |
| <i>Shoulder</i> | 15th March, 07:00   | 10th May, 06:59     | Shoulder (25 °C)            | Winter (20 °C)                |
| <i>Winter</i>   | 10th May, 07:00     | 20th October, 06:59 | Winter (20 °C)              | Winter (20 °C)                |
| <i>Shoulder</i> | 20th October, 07:00 | 1st December, 06:59 | Shoulder (25 °C)            | Winter (20 °C)                |

### 9.3 ANCILLARY SERVICES / OPERATIONAL RESERVES

The System Operator procures active and reactive power resources to provide a level of operating reserve sufficient to manage changes in load, generation and transmission equipment availability.

Reserve requirements are determined based on offered/available transmission assets and the N-1 (including N-G) criteria. Reserves are procured considering technical and economic factors. System Operator uses the Reserve Management Tool (RMT) and Scheduling, Pricing and Dispatch (SPD) application to calculate the amount and type of reserve required to maintain quality standards (frequency, voltage and time deviation) post-event for an optimal cost.

System Operator procures the following Ancillary Services:

- Frequency Keeping;
- Under frequency reserve - Fast and Sustained Instantaneous Reserve;
- Over-frequency reserve;
- Reactive reserve – voltage support contracts;
- Black start capability.

Frequency keeping reserve is procured to maintain frequency within the normal frequency band of 50 Hz +/- 0.2 Hz.

Fast and sustained under-frequency instantaneous reserve requirements are calculated from the requirement to arrest an under-frequency excursion following the loss of the largest generating unit on the system. Instantaneous reserve requirements are calculated for both the South Island and North Island and comprise a 6 second reserve (FIR) and a 60 second reserve (SIR). FIR and SIR reserve is made up of Partially Loaded Spinning Reserve (PLSR), Interruptible Load (IL) and Tail Water Depressed Reserve (TWDR).

Over-frequency reserve is procured on the South Island to maintain frequency following the loss of the HVDC link during north transfer. Over-frequency reserve is not procured on the North Island.

Reactive reserve is procured in order to maintain voltage at certain power system busbars and is usually provided by online condensers and SVC devices. Reactive reserve is arranged via voltage support contracts as required. Contracts for voltage support exist with the owners of the following plant:

- OTA GT's 1 and 2;
- OTA GT's 4, 5 and 6;
- SWN GE105.

Black start capability is procured to ensure that generation units can start without external electrical supply within a given period. It requires the provision of self-contained power supply from batteries, diesel generators or gas turbines to start up power-station auxiliaries.

### 9.3.1 INSUFFICIENT RESERVES

Where additional generation that would cover a contingent event is available but not offered, System Operator issues a Warning Notice (WRN) ahead of time in an attempt to elicit market response.

Where insufficient reserves exist or will exist, (i.e. where there is less than a minimum of a 10 minute off-load time for any circuit for longer than 30 minutes), System Operator issues a Grid Emergency Notice (GEN) stating the trading period that reduced security applies. This assumes it is not possible to constrain the circuits affected by bringing on additional generation because it is not offered or does not exist. Where load shedding will be required, consideration is given to limiting load pre-contingency to ensure a reasonable post-contingency management time.

## 9.4 SPECIAL PROTECTION SCHEMES

Automatic post-event action is facilitated by the use of Special Protection Schemes (SPS), also known as operational intertripping schemes. Automatic special protection schemes are designed to prevent abnormal system conditions occurring, such as overvoltage, overload, instability, etc. following power system fault(s) and the associated fault clearance. The action of a SPS takes place within the period of voltage recovery following fault clearance.

In addition to system re-configuration, schemes may control generation, load or other network components. The use of special protection or intertrip schemes is common practice on the New Zealand power system and all international power systems reviewed. The design of sophisticated

schemes allows greater utilisation of assets and in many cases offers an alternative to network reinforcement. The reliable operation of special protection schemes is essential to maintaining power system security.

The following Table 9-4 lists all the special protection schemes available to the System Operator.

Table 9-4 Summary of Special Protection Schemes

| Special Protection Schemes  | Purpose  | Armed   | Region                 |
|---|--|---|------------------------|
| <i>Overload Load Protection Scheme</i>                                |  |   |                        |
| <i>Arapuni Kinleith overload protection scheme</i>                    | This scheme assists with managing security during outages in and around the Bay of Plenty area.  | Normally disabled.<br><br>Only enabled when it is necessary to split the 110 kV through transmission on the KIN-TRK circuits at KIN to manage an outage in the region or managing n-1 on ARI-KIN circuits would require load management at KIN. | Bay of Plenty          |
| <i>Blenheim-Kikiwa 110 kV circuit overload protection</i>             | This scheme provides automatic corrective action following an event which results in BLN being fed from KIK only, i.e. a BLN-STK 1 & 2 double-circuit tripping.  | Normally enabled  | Nelson-Marlborough     |
| <i>Hepburn-Roskill 110 kV circuit overload protection</i>             | This scheme allows HEP-ROS split to be closed to increase the transfer limit into the North Auckland and Northland area, and manage the N-1 loading on the HEP-ROS circuits.   | Normally enabled  | Northland and Auckland |
| <i>Henderson-Otahuhu automatic line overload load shedding scheme</i> | This scheme manages the loading on any one of the through circuits, HEN-OTA-1 and HEN-SWN-1/OTA-SWN-1 during a planned outage on the other circuit(s) to adhere to a Resource Management Act limit.  | Normally disabled<br><br>Only applies for the duration of a planned outage of a HEN-OTA 220 kV circuit outage.  | Northland and Auckland |
| <i>Penrose 220/33 kV transformer overload shedding scheme</i>         | This scheme is installed to avoid a total loss of supply to Auckland that may result from a scenario where one of PEN T8, T9 or T11 is out of service, a second bank trips and the remaining bank trips on overload.   | Normally enabled  | Auckland               |
| <i>Islington-Springston overload protection scheme</i>                | Disconnection of Springston busbar following the loss of a Islington-Springston circuit.   | Normally enabled  | Canterbury             |
| <i>Stoke T7 temporary intertrip scheme</i>                            | This scheme ensures N-1 security is maintained during planned or unplanned outages of a KIK-STK 220 kV circuit to avoid overloading of the 110 kV circuits between STK and KIK.  | Normally disabled.<br><br>Only applies for the duration of a KIK-STK 220 kV circuit outage  | Nelson-Marlborough     |
| <i>Stoke T7 outage intertrip scheme</i>                               | This scheme manages the loading on KIK-STK-3 for long term outages of STK T7 during low COB generation. Management of a STK T7 outage also requires the enabling of the BLN-KIK Overload Scheme.   | Normally disabled.<br><br>Only applies for the duration of a STK T7 outage.   | Nelson-Marlborough     |
| <i>Mangamaire overload trip and autochangeover scheme (OTAS)</i>      | The overload scheme manages the N-1 loadings on the 110 kV circuits south of Woodville for a tripping of a parallel 220 kV circuit between BPE-HAY, during HVDC South transfer, high Wellington load and high TAP generation.<br><br>The autochangeover scheme improves the security of supply for MGM when the overload scheme has operated (leaving MGM fed from MGM-WDV-1). | Normally disabled.<br><br>GO will offer scheme to SO as required  | Central North Island   |

| Special Protection Schemes  | Purpose  | Armed  | Region               |
|---|--|--|----------------------|
| <i>Bombay 110 kV system split intertrip scheme (SSIS)</i>             | This scheme provides N-G-1 transmission security into Auckland.  | As specified by Operations Planning, generally for: <ul style="list-style-type: none"> <li>▪ Prolonged outage of OTC, or</li> <li>▪ Planned or unplanned outages of major 220 kV circuits into Auckland</li> </ul> | Auckland             |
| <i>Studholme system split intertrip scheme (SSIS)</i>                 | This scheme allows the STU split to be closed, and manage N-1 on 110 kV circuits as the Studholme split is normally closed during the period of October to the end of April.   | Normally enabled during spring, summer and autumn.<br>Disabled when STU split open.  | Otago & Southland    |
| <i>Timaru intertrip scheme</i>  | This scheme allows the STU split to be closed, and manages under-voltage conditions at Timaru for a planned and unplanned outage of ASB-TIM-TWZ 220 kV circuit resulting in a total loss of the TIM 220 kV interconnection.  | Normally enabled when STU split is closed.   | Otago & Southland    |
| <i>Hawera Reactor and Auto Bus Splitting scheme (ABSS)</i>            | This scheme limits generation export out of the Taranaki region to manage steady state and post contingent event loadings on HWA-WVY-1, especially when power transfer south is occurring.   | Auto Bus Splitting scheme - normally disabled<br><br>Reactor - Operations Planning will determine if it is to be enabled/disabled as per operational requirements of SO  | Taranaki             |
| <i>Kaitimako intertrip scheme</i>                                     | This scheme manages the loading on KMO-MTM-TGA-2 circuit, for contingency on either KMO-MTM-1 or KMO-TGA-1.  | Normally enabled   | Bay of Plenty        |
| <i>Tokaanu 128 intertrip scheme</i>                                   | The scheme allows a higher pre-contingency loading on the TKU-WKM circuits, thereby increasing energy transfer through central North Island, especially, during periods of high HVDC transfer north coupled with high levels of Taranaki generation.   | Normally enabled   | Central North Island |
| <i>Coleridge intertrip scheme</i>                                     | This scheme allows COL to generate unconstrained pre-contingency during an outage (planned or unplanned) of either of the COL-HOR circuits.  | Normally enabled   | Canterbury           |
| <i>Manapouri generation intertrip scheme</i>                          | The scheme allows MAN to generate unconstrained up to its maximum station output in steady state and manage dynamic stability limits.  | Normally enabled   | Otago & Southland    |
| <i>Haywards-Takapu Road overload and Takapu Road intertrip scheme</i> | The TKR intertrip scheme (TRK ITS) is designed to avoid overloading of WIL T8 when there is only one of the two HAY-TKR circuits in service, and will trip the TKR-PNI-PRM 1 and 2 110 kV circuits for a loss of the second HAY-TKR circuit.<br><br>The TKR automatic overload management scheme (TKR AOMS) caters for an n-3 event, i.e. if both 220 kV circuits to WIL are out of service, the load to WIL, CPK, KWA, TKR, PNI and PRM is supplied from the two HAY-TKR circuits. The SO may need to restrict load on the HAY-TKR 110 kV circuits so that if one circuit trips i.e. n-3 event, then the other circuit does not overload. | Normally disabled after the replacement of Wilton T8   | Wellington           |
| <i>Atarua intertrip scheme</i>  | This scheme manages N-1 security and voltage stability in the West Coast region for a planned or unplanned outage of ATU-RFN-IGH-1.  | Normally enabled   | West Coast           |

| Special Protection Schemes                           | Purpose   | Armed   | Region               |
|--|---|---|----------------------|
| <b>Automatic Under Voltage Load Shedding (AUVLS)</b> |   |   |                      |
| <i>Upper South Island</i>                            | AUVLS schemes have been installed at STK, BLN, PAP, SPN and HOR.<br><br>The AUVLS schemes are offered to the SO to use for management of voltage stability as determined by system configuration and capacity for planned outages.<br><br>Note: The AUVLS scheme at HOR is normally enabled.  | The Upper SI AUVLS is enabled to meet system security requirements at the request of the SO.<br><br>The customer will be advised of the impending enabling of the AUVLS scheme(s) for planned outages.<br><br>Affected customers are notified after the scheme is enabled for real-time system requirements or in response to a GEN or WRN. | Upper South Island   |
| <i>Hororata</i>                                      | This scheme manages the HOR 66 kV voltage for the loss of a HOR-ISL circuit .   | Normally enabled  | Canterbury           |
| <b>Runback Scheme</b>                                |   |   |                      |
| <i>Arapuni</i>                                       | This scheme provides automatic corrective action to reduce generation at ARI should an overload be detected on either of the ARI HAM circuits, thereby allowing ARI generation to be maximised.   | Normally enabled  | Waikato              |
| <i>Cobb</i>  | This scheme provides automatic corrective action should loading exceed 184 amps on either of the COB circuits, thus removing the need for n-1 constraints to be applied pre-event, thereby allowing COB generation to be maximised.   | Normally enabled  | Nelson-Marlborough   |
| <i>Maraetai</i>                                      | This scheme manages the loading on MTI-WKM 1 and 2. Winter rating - allows MTI and WPA to generate unconstrained pre-contingency. Summer day rating - permanent constraint in place to limit MTI & WPA generation to ensure runback will ramp back quickly enough to prevent thermal overload, thereby maximising MTI generation.             | Normally enabled  | Central North Island |
| <i>Te Apiti</i>                                      | This scheme monitors the current flow in each of BPE-WDV 1 & 2 and MGM-WDV 1 and will automatically reduce generation if any one overloads. As each circuit is monitored individually, the scheme can remain in service for outages on any of BPE-WDV 1 or 2, or MGM-WDV 1 and still perform its function, thereby maximising TAP generation. | Normally enabled  | Central North Island |

**Note:** as at 2<sup>nd</sup> November 2010

#### 9.4.1 OVERLOAD PROTECTION SCHEMES

Special protection schemes to open circuits that would otherwise overload are either referred to as overload protection schemes or intertripping schemes. There are cases where intertripping schemes are only enabled during outages or will only operate following an overload condition if a prior tripping has occurred. Special protection schemes that involve the action of busbar section circuit breakers to regulate power flows on the system are referred to as auto busbar splitting schemes (ABSS). An intertrip that results in a system split is referred to as a system split intertrip scheme (SSIS).

Overload protection schemes are designed to trip circuits if overloads occur for longer than a specified time. A programmed time delay will allow time for auto-reclose operations to occur but will ensure circuits do not exceed short term ratings should an auto-reclose be unsuccessful.

The action of overload protection schemes that switch out overloaded circuits may result in loss of supply to GXP(s). For example following the loss of one Islington-Springston circuit, and subsequent failed reclose attempt, a special protection scheme opens breakers to disconnect the Springston busbar from the network resulting in loss of supply to Springston.

#### 9.4.2 PLANNED AUTOMATIC LOAD SHEDDING

System Operator will employ automatic post-event load shedding schemes as necessary to manage events where such schemes are available. There are only two planned automatic load shedding schemes on the New Zealand network, one at Hororata and another at Blenheim.

Planned automatic load shedding action is employed at Hororata to manage under voltage conditions. Load shedding at Blenheim, when employed the scheme manages the loading of the Blenheim-Kikiwa circuit during outages. In both cases the load shedding scheme is facilitated with the use of AUVLS relays and occurs within an 8 second time period. The load shedding scheme trips feeder circuit breakers in a sequence to bring load below an overload trip setpoint, or to bring voltage to within allowable limits. These load shedding schemes will result in loss of supply to all load on the feeder. Automatic under-voltage load shedding (AUVLS) relays do not disable feeders used for the automatic under-frequency load shedding (AUFLS) scheme as defined in the EGRs.

An AUVLS scheme for the Upper South Island and Nelson-Marlborough may be necessary during times of high system loading in winter as a post-contingency measure to maintain the N-1 voltage stability margin and prevent cascade voltage collapse should a contingency occur. The scheme acts to protect the system by tripping load when the voltage drops.

#### 9.4.3 GENERATION RUNBACK

Generation may be automatically reduced post-event to a pre-arranged value to remove circuit overloads or generator instability. While installed to provide automatic action in a contingency, runback operation is not dependent on there being a contingency. A runback will be initiated when:

- the runback scheme is enabled, and
- circuit protection detects that loading on specified circuits exceeds a pre-determined limit.

If the circuit loading is not reduced within an inverse time dependent period after a runback scheme operation has been initiated, the circuit will be tripped.

Transpower has automatic runback schemes installed at Arapuni, Cobb, Maraetai and Te Apiti. Runback schemes may allow operation to 5 or 10 minute off-load times on monitored circuits rather than the standard 15 minute criteria.

### 9.5 REACTIVE RESERVES / OPERATION OF REACTIVE DEVICES

System Operator will dispatch available static reactive devices so that dynamic reactive reserves are available to provide voltage support for contingent events and extended contingent events.

Where condensers are required, it is necessary to ensure that they are in service prior to the commencement of the outage.

## 9.6 GRID RECONFIGURATION

Under certain conditions system reconfiguration may be implemented to prevent circuits overloading. Grid re-configuration may include:

- Creating a temporary system split. This may put some parts of the grid on N-security;
- Closing or moving a permanent system split;
- Selecting transmission circuits to a different busbar to resolve issues resulting from a busbar section outage.

### 9.6.1 TEMPORARY SPLITS

Temporary splits may occur as a result of action of an intertrip system, such as an overload protection and autochangoover scheme. (i.e. as found on the Mangamaire-Woodville 110 kV circuit)

### 9.6.2 PERMANENT SPLITS

The need to establish a permanent system split will be made by operations planning engineers in consultation with the Grid Owner, and will normally result from a determination that splitting the system at a given point will enhance overall powerflows across the remaining parallel paths.

There are three permanent splits on the New Zealand network:

- Fernhill - Waipawa (FHL-WPW);
- Mangahao - Paraparaumu (MHO-PRM);
- Edgumbe Interconnectors - (EDG T4 & T5).

**Note:** The Mount Roskill split is now removed – normal configuration as from 23 March 2009 is with the Hepburn Road-Mount Roskill (HEP-ROS) circuits in service with overload protection applied, allowing parallel operation with the 220 kV network

The conditions under which they may be temporarily reconfigured will be determined through consultation between the System Operator and the Grid Owner.

The Fernhill-Waipawa (FHL-WPW) split is only closed following the non availability of:

- Redclyffe-Wairakei 1 and either Whirinaki -Wairakei 1 or Redclyffe-Whirinaki 1, or
- both Redclyffe interconnectors T3 and T4.

A system split between Bunnythorpe (BPE) and Takapu Road (TKR) is required to prevent serious overloading of the 110 kV circuits (or alternatively the application of significant system constraints) in the event of a 220 kV circuit contingency. The split may be moved following the non availability of:

- both Pauatahanui-Takapu Road (PNI-TKR) circuits 1 and 2, or
- both Paraparaumu-Takapu Road (PRM-TKR) circuits 1 and 2, or
- both Bunnythorpe-Mangahao (BPE-MHO) circuits 1 and 2.

With additional generation injection into the Kawerau (KAW) 110 kV busbar following the commissioning of KAG, constraints need to be applied to maintain N-1 on EDG-KAW 1 and 2. A system split on the LV breakers of EDG T4 and T5 provides constraint relief during normal system operation. The System Operator may close the system split where it considers this action is necessary for maintaining or restoring supply or for system integrity.

### 9.6.3 BUSBAR SECTION SPLITS

The Otahuhu 110 kV bus is normally operated split. The split was implemented some years ago as a measure to manage load sharing on the Otahuhu and Penrose interconnecting transformers, and to control fault levels on the Mangere and Mount Roskill 110 kV buses. The Otahuhu 110 kV split can be closed to resolve outage issues where necessary, it is unlikely for Otahuhu bus split to be closed as a post-contingency measure

The Manapouri busbar is normally operated closed. The Manapouri busbar split is opened during bus zone protection outages in order to remove the risk of losing the complete station. Action is not normally taken to manage the risk of a busbar tripping during bus zone protection outages. However, as Manapouri generation is critical to the management of system security in Southland, actions at Manapouri are taken to minimise the consequences of a busbar fault during a bus zone protection outage.

In general, should a busbar fault occur where there is no bus zone protection (including where the bus zone protection is switched off), busbar fault clearance will be initiated from the remote ends of the circuit(s) feeding into that bus and the complete busbar will be lost.

## 9.7 HOT STANDBY

There are a number of transformers unloaded but on 'hot standby'. Following the loss of a parallel connected transformer the transformer on hot standby will be able to pick up the load and maintain supply. A list of transformers on hot standby is given in Table 9-5.

*Table 9-5 Transformers in Service and on Hot Standby*

| Name                            | Description  |
|---------------------------------|--|
| <i>Bromley (BRY) 66/11 kV</i>   | Only two of T2, T3 & T4 are permitted to be in service at any one time   |
| <i>Addington (ADD) 66/11 kV</i> | Only two of T5, T6 & T7 are permitted to be in service at any one time   |
| <i>Papanui (PAP) 66/11 kV</i>   | – No restriction with 11 kV Busbar Split (normal configuration)<br>– A maximum of three of T1, T2, T3 & T4 permitted to be in service when 11 kV busbar is tied. |
| <i>Hamilton (HAM) 220/55 kV</i> | T8 is to remain in service with T7 on hot standby unless T8 is removed from service  |

## 9.8 AUTOMATIC UNDER FREQUENCY LOAD SHEDDING (AUFLS)

In order to ensure that events larger than a single contingent event will not result in a cascade failure, automatic corrective action is required. AUFLS load shedding is initiated by frequency sensing relays and will trip load as follows:

- in 2 blocks (termed Block 1 and Block 2).

- at predetermined frequencies for each block, with time delay as set out in *Table 9-6*.
- at grid exit points determined by the System Operator in consultation with asset owners.
- as identified by asset owners, however expect it to be the lower priority loads.
- in quantities in each Block at least equal to 16% of the connecting parties total load off-take at any point in time. "Connecting parties" includes lines companies and direct connects.
- Interruptible Load will also have tripped as a result of an AUFLS operation. However, load offered as interruptible load is not to be considered for AUFLS.
- An operation of AUFLS will constitute a Grid Emergency.
- The Security Co-ordinator will manage restoration of load following an AUFLS operation by issuing instructions to the Regional Operator.

*Table 9-6 Summary of Automatic under frequency load shedding settings*

| Demand Block         | Operation Frequency (NI) | Operation Frequency (SI) | Time Delay  |
|----------------------|--------------------------|--------------------------|-------------|
| <i>Block 1 (16%)</i> | 47.8 Hz                  | 47.5 Hz                  | 0.4 seconds |
| <i>Block 2 (16%)</i> | 47.5 Hz                  | 45.5 Hz                  | 15 seconds  |
|                      | 47.5 Hz                  | 45.5 Hz                  | 0.4 seconds |

**Note:** The time delay is the maximum time from when the frequency is detected as reaching the limit, and the disconnection of the demand blocks.

An AUFLS scheme is installed in the North Island to automatically shed load for an event greater than a single contingent event. Likely events that could result in an AUFLS operation are a HVDC bipole trip in *north transfer*, and/or the loss of a busbar or busbar section onto which multiple generating units connect. The loss of a busbar with multiple generator units connected will only result in AUFLS operation when the sum of the generator units is greater than the largest single unit risk on the network.

Likely events that could result in South Island AUFLS operation are a HVDC bipole trip in *south transfer* and/or the loss of a busbar or busbar section onto which multiple generating units connect. AUFLS would operate only in the event where the sum of generating units connected to the busbar is greater than the largest single unit risk on the south island network.

During south transfer the loss of a busbar in the lower North Island will result in the manual trip of the HVDC pole. During north transfer the loss of a busbar in the South Island in the vicinity of Benmore is likely to result in the manual trip of the HVDC pole. In both of these cases the action of AUFLS is unlikely to take place.

## 9.9 EMERGENCY OPERATION

Under emergency schedules, transmission system operators specify actions to manage faults or system states not covered by N-1. Because not all contingencies or combination of contingencies can

be accounted or planned for, emergency and restoration plans are introduced and must be sufficient for system restoration and black start capability.

For the New Zealand system any of the following is considered to be a grid emergency for the purposes of the Grid Operating Security Policy:

- either the frequency or the voltage are markedly outside normal limits and urgent action is required either to avoid damage to equipment or to avoid a grid collapse;
- there is an actual imbalance between supply and demand (beyond the capacity of the frequency regulating reserves), or such an imbalance is anticipated by the grid operator, or
- there is a loss of communication that affects or is likely to affect the operation of the grid.

System Operator's emergency procedures involve the issue of Grid Warning Notices (WRN) and Grid Emergency Notices (GENs). Grid Warning Notices are issued prior to two hours before the start of the relevant trading period. Grid emergency notices are issued within two hours prior to the start of the relevant trading period or during the relevant trading period.

Following the issue of a grid emergency notice System Operator may employ "Demand Management" measures if participant responses to the GEN do not mitigate the grid emergency. The need to manage demand may be identified from:

- insufficient offers of generation, instantaneous reserve, transmission and/or reactive support to supply the expected load (including transmission losses), provide frequency keeper regulating band and provide security for defined events;
- an unplanned event (typically greater than a contingent event) resulting directly or indirectly in load loss or the need to take prompt action to correct steady state frequency, equipment loadings, voltage or voltage instability;
- an inability to restore frequency reserves within 30 minutes post event;
- an inability to restore N-1 security post event where there is a high probability of a second event.

Demand management measures include the issue of Demand Allocation Notices (DANs) that request a quantity of demand reduction for a specified time or the issue of instructions for distributors or grid owners to disconnect demand at required points of connection. During a grid emergency, generators and ancillary service agents should endeavour to take independent action to correct extreme under-frequency, over-frequency and voltage conditions.