Security and Reliability Council

# The National Winter Group's report on winter 2015

9 March 2015

**Note:** This paper has been prepared for the purpose of the Security and Reliability Council (SRC). Content should not be interpreted as representing the views or policy of the Electricity Authority.

## Background

The Security and Reliability Council's (SRC) functions include offering advice to the Electricity Authority on the security of the power system.

The National Winter Group (NWG) is a group of industry participants that is established to determine possible power system issues during the winter season. The NWG has reported on the ability of the power system to meet peak demand for every winter since 2008. It began in response to concerns about security of supply during winter 2008.

The intent of the NWG is to:

- develop an agreed industry participant view of likely demand and generation to provide a common view on issues and risks for the winter season
- identify appropriate measures that could be implemented to mitigate risks.

The system operator is the convener of the NWG.

## The National Winter Group's report on winter 2015 is complete

The NWG report on winter 2015 shows that the power system is expected to be able to meet the 95$^{th}$ percentile of peak demand using the 10$^{th}$ percentile of generation availability while remaining in a 'normal secure state'.

This is the same conclusion as in last year's NWG report. A reduction in the demand forecast has largely been countered by a reduction in assumed available generation.

The starting assumptions about percentiles have been determined by the NWG to be "prudent". As such, the results indicate that the power system is expected to maintain normal security in a rare/conservative scenario.

The result can inform only about power system capability, not about whether it is a 'good' or 'bad' result for electricity consumers. The NWG acknowledges that its report is a discussion starter – it is not intended to inform about what action, if any, might be needed.

## The contents of the report have been enhanced since 2014

In October 2014, Transpower presented to the SRC on the future development of the NWG report. Transpower's proposals included:

- consulting with the industry and Authority as to how the report can be improved
- reconciling the report against other similar reports such as the Annual Assessment of Security of Supply
- reviewing the reporting frequency
- reviewing the demand forecasting methodology
- ongoing developments, including data and presentational enhancements.

The NWG report on winter 2015 incorporates a number of enhancements, including additional peak load forecast information, a comparison of the North Island capacity margin with previous years and several presentation improvements. However, the NWG endeavours to provide the most useful information to the relevant stakeholders and is therefore open to suggestions and feedback on content and methodology.

The SRC may wish to consider the following questions.

| | |
|---|---|
| **Q1.** | Does the result of the National Winter Group report give the SRC confidence in the suitability of power system capabilities? |
| **Q2.** | In the SRC's view, what further improvements, if any, should be made to the content and/or presentation of the NWG report? |

# NWG Report 2015

## Draft Report

Prepared on behalf of the National Winter Group by Market Operations, System Operator, Transpower

4/03/2015


SYSTEM OPERATOR

Keeping the energy flowing

TRANSPOWER

Transpower New Zealand Ltd The National Grid

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# 1 Purpose

The purpose of this report is to advise electricity industry participants of the peak capacity outlook for winter 2015, as identified by the National Winter Group (NWG). This is done with the aim of identifying any potential issues in meeting peak winter demand; and to provide an indication of any need for remedial action.

## 1.1 National Winter Group 2015

The defining features of NWG 2015 are:

- Contact Energy's Taranaki Combined Cycle (TCC) plant on standby
- Withdrawal of a second Huntly unit (250 MW) from the market
- Reduced peak island load forecasts from 2014

### *1.1.1 Taranaki Combined Cycle on Standby*

Contact Energy expects its gas-fired Taranaki Combined Cycle station to be on standby during winter 2015 due to reduced contracted fuel quantities[1]. In case of a generation shortage, the plant may be available but requires approximately 72 hours to complete start up procedures. As such, TCC does not fall into the "slow uncommitted" category for 2015 and is disregarded for the purposes of the NWG analysis.

### *1.1.2 Withdrawal of a Second Huntly Rankine Unit*

Genesis Energy placed one of its three remaining 250 MW Rankine units into long-term storage at the end of 2013[2]. A return to service would require up to 90 days and will only be carried out under exceptional circumstances. One of the original four units ceased operation permanently early in 2013 and is undergoing a full decommissioning process. For the purposes of this year's NWG analysis, one of the two remaining units is assumed to be offered and available and the other is included in the slow uncommitted category.

### *1.1.3 Reduced Peak Demand Forecast*

Relative to 2014, the 95$^{th}$ percentile peak demand forecast values for 2015 are approximately 3% lower in the North Island and 5% lower in the South Island. This is a significant drop, compared to previous forecast demand changes between successive years. The change is largely due to the 10 year peak demand trend; more of the recent low growth period is now reflected in the forecasts. See appendix 5.2 for more details.

1 See http://www.contactenergy.co.nz/aboutus/pdf/financial/cen-fy14-investor-presentation.pdf

2 See https://www.genesisenergy.co.nz/huntly-power-station-plant-description

## 1.2 Nature of this Report

The aim of the National Winter Group is to determine the ability of the power system to meet peak winter demand. This entails having sufficient generation capacity offered in the market at the time of peak winter demand to avert the need for a Grid Emergency to be declared, and the consequential actions that can follow. The System Operator has separate processes to manage “dry year” risk where there may be insufficient fuel to meet demand.

As an outcome of the NWG 2008, it was identified that first establishing the demand and generation balance would provide a greater focus to any subsequent options work. This methodology has been carried over to the NWG 2015 report. The report is a view of the power system’s ability to meet peak demand, in advance of any work to identify the options to address the possible risks presented herein. As such, it is the completion of the first stage of the NWG process and results may change if or when any options work is undertaken.

The NWG is a result of collaboration, consultation and co-ordination within the New Zealand electricity industry. The views and recommendations expressed in this report and its attachments are drawn from the individual contributions and expertise of the various NWG members. They should not be read as in any way reflecting the views or positions of specific industry participants.

# 2 Process

To determine the ability of the power system to meet peak winter demand the NWG considers the worst case of peak demand and lowest generation capacity by island over the winter months of June to August.

The two workstreams of the NWG are Demand and Generation. Comparing results of the Demand and Generation workstreams provides to the results presented in section 3.

The Demand workstream is responsible for determining a prudent peak demand figure for winter 2015 with a 95% probability. This is a peak winter demand value with only a 5% chance of being exceeded. For winter 2015 the prudent peak demand values determined by the Demand workstream are 4886 MW for the North Island and 2348 MW for the South Island. For detailed information on the Demand workstream see section 5.2 in the appendices.

The Generation workstream is responsible for determining week-by-week generation availability with a 10% probability. This is a generation availability value with a 90% chance of being exceeded. The generation stack takes account of outages that occur during the winter, thereby reducing the available generation capacity. The assessed outage values for winter 2015 are summarised in the flowing sections (based on POCP notified outages as of 11 February 2015). Additional details of the Generation workstream are in section 5.3 in the appendices.

For detailed information on the outage values assessed see sections 5.3.12 and 5.6 in the appendices.

The nett generation capabilities (taking account of outages) determined by NWG 2015 are presented graphically below.

## 2.1 North Island

*Table 1: North Island assessed coincident outages*

| Outage type | 01/06 - 07/06 | 8/06 - 14/06 | 15/06 - 21/06 | 22/06 - 28/06 | 29/06 - 05/07 | 06/07- 12/07 | 13/07 - 19/07 | 20/07 - 26/07 | 27/07 - 02/08 | 03/08 - 09/08 | 10/08 - 16/08 | 17/08 - 23/08 | 24/08 - 30/08 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Thermal | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Geothermal | 9.4 | 14.4 | 14.4 | 9.4 | 9.4 | 0.0 | 14.0 | 0.0 | 51.0 | 0.0 | 14.0 | 30.0 | 0.0 |
| Cogeneration | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Hydro Storage | 177.1 | 212.3 | 177.1 | 177.1 | 177.1 | 141.9 | 141.9 | 156.1 | 85.7 | 147.9 | 115.9 | 70.4 | 61.2 |

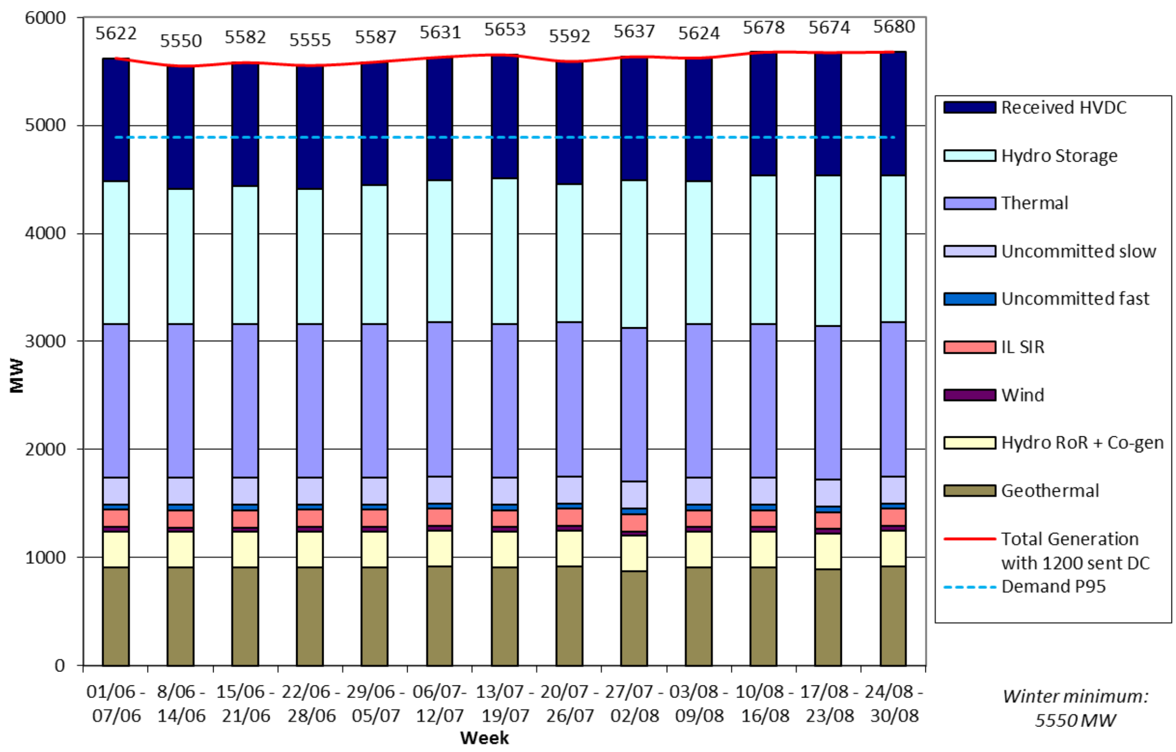


*Figure 1: North Island minimum generation stack for June – August 2015*

The relevant prudent peak demand forecast has been overlaid against generation availability on Figure 1 above. Of note is that the North Island generation stack exceeds forecast peak demand in every week of winter 2015, before consideration is made of reserve requirements.

The minimum in the North Island generation during the second week of the assessment period corresponds to coincident outages at the Te Rapa Co-generation station; Nga Awa Purua and Ohaaki geothermal stations and multiple stations in the Waikato River hydro scheme. The total is a similar magnitude to the observed worst-week North Island total in 2014.

## 2.2 South Island

*Table 2: South Island assessed coincident outages*

| Outage type | 01/06 - 07/06 | 8/06 - 14/06 | 15/06 - 21/06 | 22/06 - 28/06 | 29/06 - 05/07 | 06/07- 12/07 | 13/07 - 19/07 | 20/07 - 26/07 | 27/07 - 02/08 | 03/08 - 09/08 | 10/08 - 16/08 | 17/08 - 23/08 | 24/08 - 30/08 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Hydro Storage | 502.0 | 380.5 | 314.5 | 281.5 | 191.5 | 178.0 | 407.5 | 233.0 | 244.0 | 339.0 | 427.5 | 308.0 | 218.0 |

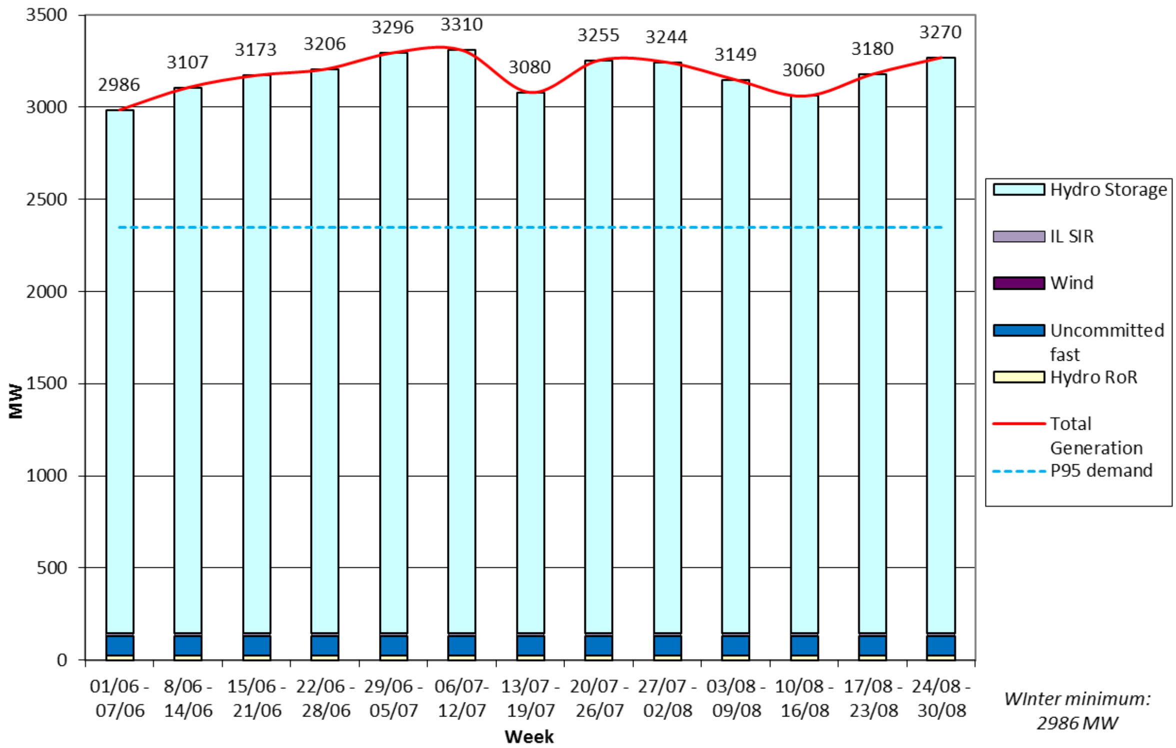


*Figure 2: South Island minimum generation stack for June – August 2015*

The South Island minimum occurring in the first week of the assessment period, shown on Figure 2, corresponds to coincident outages at the Manapouri and Clyde hydro stations and multiple stations in the Waitaki River hydro scheme. The value is reduced from the observed worst-week South Island total in 2014.

# 3 Results

The results below pertain to evening demand peaks, on weekdays only, during the winter months of June, July and August 2015. The implications of these results for system security are summarised in section 3.4.

## 3.1 North Island

The worst-case 'twin peak' analysis can be seen graphically:

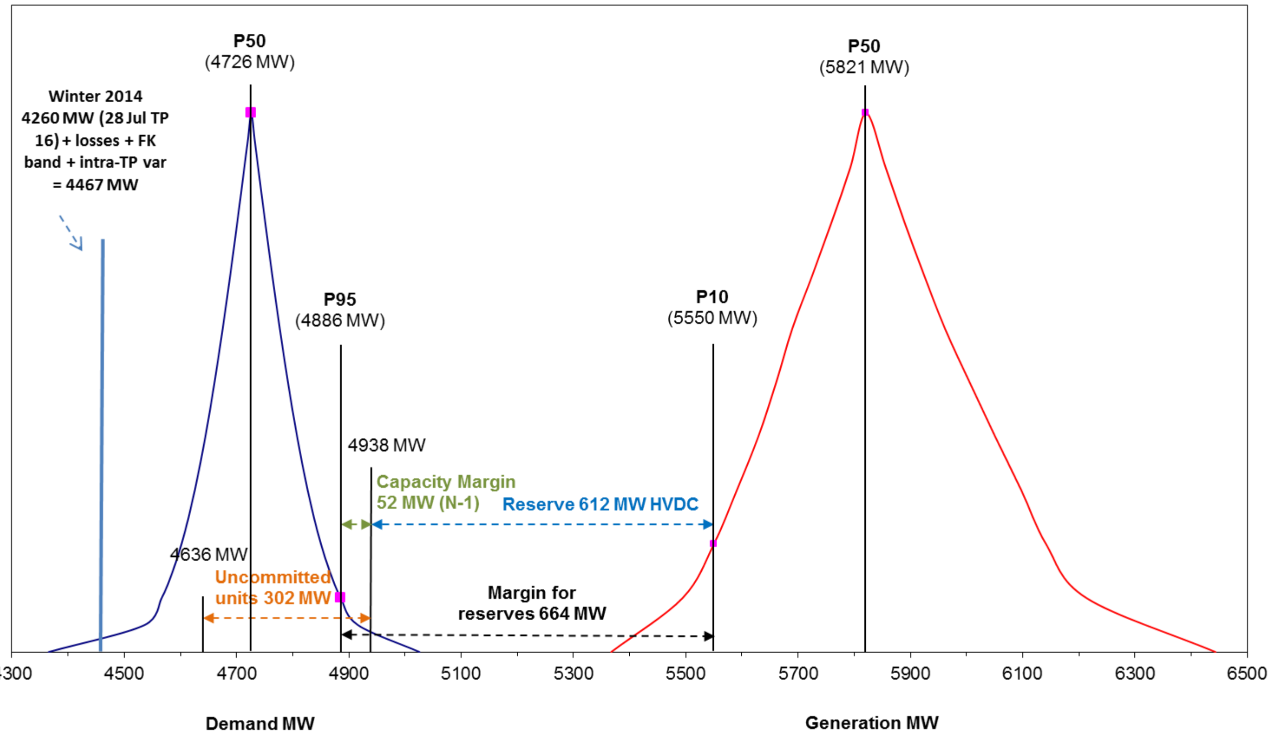


*Figure 3: North Island demand and generation balance at peak winter 2015 (HVDC available)*

Figure 3: North Island demand and generation balance at peak winter 2015 (HVDC available) shows that when 95th percentile peak demand is subtracted from 10th percentile generation availability, and reserve requirements are accounted for, there is an expected capacity margin of **52 MW**. This is an acceptable result and indicates that it is unlikely there will be major issues meeting peak winter demand. The worst case shown here persists for two days in the second week of winter (June 9th and 10th). However, the next worst-case generation availability provides only an extra 5 MW to the capacity margin.

The capacity margin from June to August ranges from 52 MW to 183 MW for the worst-case each week. Eight of the 13 weeks during winter 2015 have worst-case capacity margins of over 100 MW, with four weeks having capacity margins over 150 MW.

Provided there is full availability of plant that is not covered by notified outages, the power system will be able to be run in a normal secure state over expected winter peaks in 2015. If there is an outage of a major thermal plant (possibly up to 400 MW) there are periods when the power system may be run in an emergency secure state. However, load will only be shed if there is a further unplanned outage of major thermal plant or the HVDC link.

It is noted that the effective risk of a large thermal plant not being available over a significant winter demand peak is somewhat reduced in 2015. This is because in the event of a prolonged unplanned outage at the Otahuhu B station, Contact Energy has the ability to use contracted gas supply to generate at TCC instead.

### *3.1.1 Comparison with Previous NWG Margins*

Figure 4 below shows the identified worst-week North Island capacity margins by year from 2009 (when this metric was first reported) as stated in each year's final NWG report. The result for 2015 is the second worst year recorded, after 10 MW in 2014.

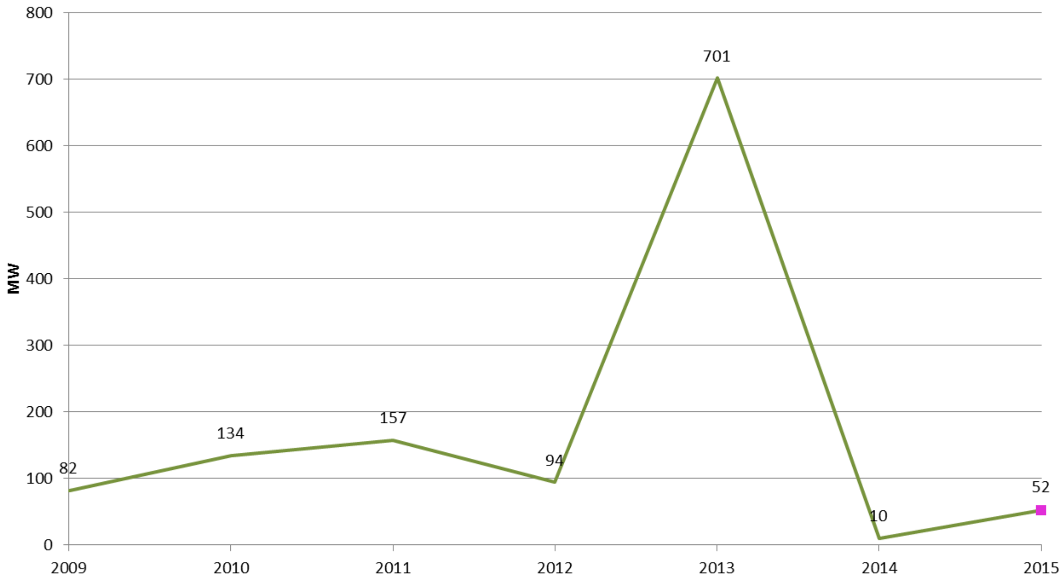


*Figure 4: Worst-week North Island capacity margins by year*

## 3.2 South Island

The 'twin peaks' analysis for the South Island:

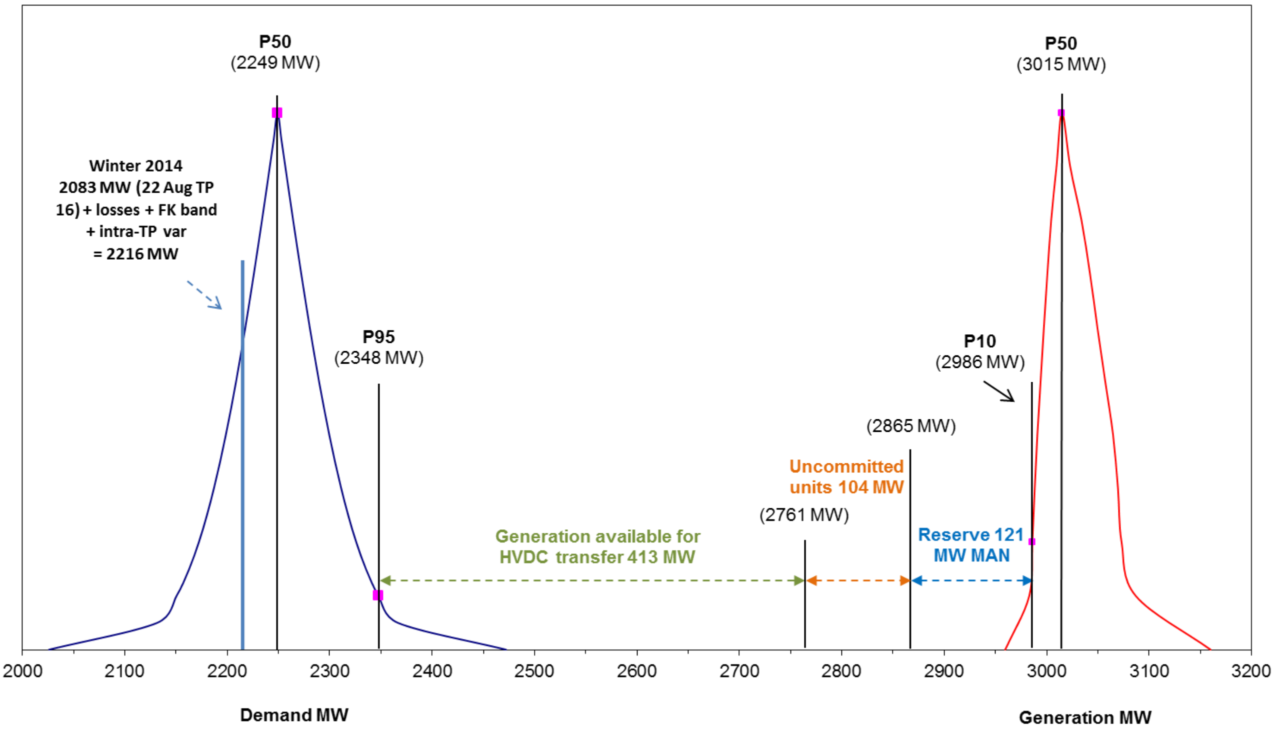


*Figure 5: South Island demand and generation balance at peak winter 2015*

Figure 5 shows that after subtracting 95th percentile peak demand, uncommitted generation and the island reserve requirement, it is expected there will be **413 MW** of generation available to be transferred northward on the HVDC link. At this level, HVDC transfer may briefly become a limiting factor for North Island supply.

The North Island and South Island demand peaks have coincided only once in the last 15 year period. In addition, the POCP outage adjusted generation stacks of both islands are not coincident in their worst cases. Therefore, the prudent forecast of generation available for North transfer is not used as a limiting received value for the North Island generation stack.

## 3.3 Further Work

The NWG 2015 has determined that there is presently no need for further options work for winter 2015 beyond the work already undertaken. The System Operator will continue to monitor developments and convene NWG industry forum if necessary.

Provided all major generating plant not covered by known outages are available during winter 2015, the power system should be able to meet the peak winter demand in a normal secure state.

## 3.4 The State of the Power System for Winter 2015

The NWG 2015 has established a view on the prudent estimate of the peak demand that is unlikely to be exceeded in winter 2015. This year's prudent peak demand is 4886 MW[3] for the North Island, up 9.3% on the actual peak winter demand in 2014. The prudent peak demand for the South Island is 2348 MW, up 5.9% on the equivalent peak demand in winter 2014.

The Generation Group analysis was conducted on an equivalent basis to previous years (2010 onwards). The generation stack includes the statistical analysis of generation availability, assumptions regarding HVDC transfer limitations and a consideration of generation outages and their effect on the available generation over demand peaks.

The results of the analysis of peak winter demand and generation availability for winter 2015 is summarised in the five key questions and their corresponding answers below. The answers to the questions reflect the ability to continue to operate the power system in one of three states.

- **Normal secure state:** *Power system status green*
  There will be no disconnection of consumers even if there is a sudden loss of a large generator or HVDC pole during the critical winter evening peak demand periods.
- **Emergency secure state:** *Power system status orange*
  There will be an automatic disconnection of a significant number of consumers[4] only if there is a sudden loss of a large generator an HVDC pole at a time of winter peak evening demand.
- **Load shedding required:** *Power system status red*
  Disconnection of consumers will be required for some critical winter peak periods to maintain the power system in an emergency secure state even without the loss of any generation or the HVDC link[5]. There is still a risk that further demand will be shed automatically following an event.

The following answers assume all generation not covered by known outages is available. In this context, "available" refers to generation being connected to the power system and ready to generate when required. The "commitment" issue for some slow starting generation is discussed in section 4.3.

[3] Demand Group prudent forecast plus system losses, the frequency keeping band, and an intra-trading period variability allowance. The prudent demand is a projection from past years with a 5% probability of being exceeded (P95).

[4] This assumes that the Automatic Under Frequency Load Shedding (AUFLS) scheme operates. AUFLS is a critical system safety mechanism to preserve the integrity of the power system by disconnecting one or two load blocks, each representing at least 16% of consumer demand in the affected island.

[5] It is necessary that the power system is in a secure state at all times (even if demand must be shed to get back to the emergency secure state).

### 3.4.1 Key Questions and Answers

The answers are based on the assessment for winter 2015. They do not reflect the impact of any initiatives from remedial work that may be forthcoming.

***Question 1:*** Can the forecast peak winter demand on the power system for winter 2015 be met?

*Answer:* There is a reasonable level of confidence that should all the generation available be committed to run that the power system will be in its normal secure state (status green) at peak winter demand. Should there be a failure or inability to commit all available units, the system may be operated in an emergency secure state (status orange).

***Question 2:*** Can the forecast peak winter demand on the power system be met if generation, equivalent to a large gas-fired combined cycle unit, is unavailable for a sustained period?

*Answer:* There is a moderate level of confidence the power system will able to be maintained in its normal secure state (status green) at peak winter demand if a large generating unit is unavailable. A possible consequence would be reverting to an emergency secure state (status orange). Timely market signals may help to mitigate this risk.

***Question 3:*** If there is already a sustained outage of a large thermal generating unit, can we still meet peak winter demand if a second such generating station stops running?

*Answer:* Even with all other generation in service it could be necessary to disconnect some consumers at peak times to maintain the power system in an emergency secure state. This question relates to a particularly onerous situation where the equivalent of two large combined cycle gas turbine stations are not running. Historically the NZ power system would not normally be able to meet this scenario at times of system peak demand.

The power system may on a few occasions move into the load shedding required state (status red), where the disconnection of some consumers would be required at peak times to return the system to the emergency secure state.

***Question 4:*** How does the capacity margin (N-1) for the North Island between prudent peak demand forecast (5% probability of being exceeded) and prudent generation (90% probability of being exceeded) for winter 2015 compared to the forecast for 2014?

*Answer:* The capacity margin is slightly higher than the 2014 forecast worst-case North Island capacity margin of 10 MW. The primary factors regarding the availability of thermal generation have not changed materially since last year.

***Question 5:*** In the past, how often has the power system been at, or near, the maximum peak winter demand?

*Answer:* Historically the power system is within 1% (ie 70 MW) of the peak winter demand for about 2 to 3 hours in a typical winter. The power system is within 5% (350 MW or close to the output of a large generating unit) for about 60 to 80 hours over a typical winter.

# 4 Background

## 4.1 National Winter Group History

The first National Winter Group (NWG 2007) was established in August 2006. The NWG 2007 was an electricity industry working group co-ordinated by the System Operator. The task set for the group was to determine the ability of the power system to meet 2007 peak winter demand. The need for the 2007 group arose from issues in meeting system peak demand in June 2006.

A NWG 2008 group was established in October 2007 at the request of the Electricity Commission and Ministry of Economic Development following the decision by Transpower to retire HVDC Pole 1. Contact Energy subsequently advised in late October that New Plymouth Power Station may not be available during winter 2008. As in 2006, the brief was to determine an industry view of the ability of the power system to meet winter peak demand using the same approach and methodologies as for the NWG 2007 work.

A NWG 2009 was established to consider changes since the 2008 report was issued. Given there had been only minor changes in the generation stock since the 2008 report, the NWG had sought further information regarding the intended use of the HVDC Pole 1 and New Plymouth station; and critically, the expected peak demand for 2009. The demand value is of particular interest given the 2008 forecast was rendered unusable due to the power saving campaigns and reaction to high price during the low hydro inflow period in winter 2008. In addition, the likely impact of the economic down-turn on peak electricity demand needed careful consideration.

For NWG 2010, one of the main concerns was the likely operating policy for HVDC Pole 1. A review was also conducted of the methodology and assumptions applied to the analysis of the Generation Group data to ensure continued relevance to the operating conditions likely to be prevalent in winter 2010. As a result of this review, a number of changes were made around the HVDC transfer limits, the analysis of the variable generation and the available North Island reserve.

The main concern for NWG 2011 was the restricted transfer capacity on HVDC Pole 2 to accommodate Pole 3 Project work.

Pole 1 was decommissioned in August 2012. This represented a loss of 135 MW in North transfer capacity of the HVDC link and a 60 MW increase in the required North Island reserve at full Pole 2 North transfer. Therefore, the NWG 2012 analysis was carried out separately for June/July and August.

The NWG 2013 analysis was affected by two major developments. Pole 3 was commissioned in May 2013. This increased available northward HVDC transfer to approximately 1200 MW. In addition, Huntly Unit 3 (243 MW) was placed into long-term storage in February 2013.

NWG 2014 was affected by reduced thermal generation availability (Taranaki Combined Cycle and an additional Huntly Rankine unit) and a major central North Island transmission upgrade limiting generation export from this region. Several South Island generation outages were shifted by generators at the request of the System Operator to mitigate identified worst weeks.

The individual members of the group have been drawn from electricity sector stakeholders and market participants. For details see the appendices, section 5.1.

## 4.2 Peak Winter Demand

Peak winter demand can place the power system under some stress requiring all generating units on the power system and most grid assets to be available in order to deliver full consumer demand. The overall New Zealand wide peak on the power system usually occurs sometime between June and August at around 5:30 to 6:30 pm on a cold weekday evening. This can be associated with a fast moving southerly storm sweeping over the country within 24 hours.

The Demand workstream of the NWG has developed prudent forecasts of the system peak for the North and South islands for winter 2015. These forecasts have a very high confidence level and are unlikely to be exceeded by the actual winter peak in 2015.

## 4.3 Enabling the Full Commitment of Generation at System peak

The current market arrangements focus on the delivery of generation to meet energy demand. Historically, the underlying assumption has been that the New Zealand power system has sufficient fast starting generation capacity available to cover peak system demand along with any sudden credible changes in generation availability.

In this report, when the forecast peak winter demand is overlaid on the generation capability stack it is assumed that all generation, both “fast starting” and “slow starting”, will be available to generate at times of peak winter demand.

### *4.3.1 Enabling the Timely Commitment of Slow Starting Generation*

The generation capability stack includes uncommitted slow starting thermal generation, which can only contribute to meeting a winter demand peak if it has been warmed up or is generating in advance. Start-up times for slow start thermal generation are between 3 and 12 hours. Therefore, if not already running, slow start generation is unlikely to be available immediately for an unexpected change in generation availability, such as the failure of a large thermal generator during the day close to a winter demand peak.

Considering the slow starting nature of this generation, it must be noted that there is a risk that the appropriate market signals are not delivered in a timely and accurate manner. This could result in the generation not being offered and therefore available when needed.

# 5 Appendices

## 5.1 NWG Membership

| Name | Organisation |
|---|---|
| Bas Van Esch | Vector |
| Rick Liew | Vector |
| John Welch | Vector |
| Richard Herries | Vector |
| Andy Anderson | Mighty River Power |
| Buddhika Rajapaske | Mighty River Power |
| Andrew Elder | Pacific Aluminium |
| Mark Kerrison | Pacific Aluminium |
| James Collinson-Smith | Contact Energy |
| Boyd Brinsdon | Contact Energy |
| Cory Franklin | Contact Energy |
| Ralph Matthes | Major Electricity Users Group |
| Michael Smith | PowerCo |
| Phil Marsh | PowerCo |
| Glenn Coates | Orion |
| Stuart Kilduff | Orion |
| John O'Donnell | Orion |
| Nigel Brown | Unison |
| Jason Larkin | Unison |
| Richard Spearman | Trustpower |
| Evan Boyt | Trustpower |
| Kwong Chung Wong | Genesis Energy |
| Jon Spiller | Meridian Energy |
| Chris Ewers | Meridian Energy |
| Tristan Maunsell | Todd Energy |
| Callum McLean | Electricity Authority |
| Tim Crownshaw | Transpower |
| Erich Livengood | Transpower |
| Hunter Humphries | Transpower |
| Gari Bickers | Transpower |
| John Clarke | Transpower |
| Si Kuok Ting | Transpower |
| Andrew Gard | Transpower |

## 5.2 Demand Workstream

### *5.2.1 Summary*

The **Demand workstream** report details the analysis carried out in establishing a prudent peak forecast for winter 2015 for both the North and South Islands as well as New Zealand overall.

The system demand figures in the Demand workstream analysis refer to average half-hour offtake from the power system at the Transpower grid/lines company interface. Other references to overall system peak demand figures in the Generation workstream report are for average half-hour injection into the power system – the energy transferred from power stations into the grid. The difference between offtake and injection are the losses in transmitting power through the grid.

The modelling of the prudent peak requires:

- A forecast of expected peak demand in 2015 (P50).
- Calculation of an appropriate margin or confidence interval to allow for the likely variation around the expected forecast resulting from changes in the peak demand growth rate, changes in ambient temperature, and changes in consumer behaviour.
- Calculation of an appropriate allowance for losses in each island and at a national level.

The load flow analysis conducted by the System Operator concludes that allowances for losses at system peak of 148 MW in the North Island and 110 MW in the South Island are appropriate.

An allowance is also made for the variation that occurs within the peak half-hour around the half-hour average load. Analysis of the variation seen within historical peak half-hours has been performed to determine appropriate allowances for this variation within future peak half-hours. These are added to the half-hour average forecasts to generate the instantaneous peak demand forecast required for planning purposes.

The results of the various methodologies for modelling peak demand are set out in Table 3, Table 4 and Table 5 below.

*Table 3: North Island peak demand forecast summary*

| ***North Island*** | | |
|---|---|---|
| ***Methodology*** | ***Expected Peak (MW)*** | ***Prudent Peak (MW)*** |
| Linear Regression (confidence interval) | 4,401 | 4,664 |
| Linear Regression (prediction interval) | 4,318 | 4,549 |
| Modified Linear Regression (High Growth) | 4,493 | 4,755 |
| Modified Linear Regression (Med Growth) | 4,483 | 4,746 |
| **Consensus** | **4,679** | |
| **Losses** | **148** | |
| **Half-hour Variability** | **39** | |
| **Recommendation for Peak Demand** | **4,866** | |

Table 4: South Island peak demand forecast summary

| South Island | | |
|---|---|---|
| **Methodology** | **Expected Peak (MW)** | **Prudent Peak (MW)** |
| Linear Regression (confidence interval) | 2,118 | 2,228 |
| Linear Regression (prediction interval) | 2,041 | 2,085 |
| Modified Linear Regression (High Growth) | 2,185 | 2,295 |
| Modified Linear Regression (Med Growth) | 2,143 | 2,252 |
| **Consensus** | **2,215** | |
| **Losses** | **110** | |
| **Half-hour Variability** | **13** | |
| **Recommendation for Peak Demand** | **2,338** | |

Table 5: New Zealand peak demand forecast summary

| New Zealand | | |
|---|---|---|
| **Methodology** | **Expected Peak (MW)** | **Prudent Peak (MW)** |
| Linear Regression (confidence interval) | 6,512 | 6,887 |
| Linear Regression (prediction interval) | 6,372 | 6,642 |
| Modified Linear Regression (High Growth) | 6,675 | 7,050 |
| Modified Linear Regression (Med Growth) | 6,614 | 6,988 |
| **Consensus** | **6,892** | |
| **Losses** | **241** | |
| **Half-hour Variability** | **85** | |
| **Recommendation for Peak Demand** | **7,218** | |

The demand group considered all approaches to have some merit and equally some weaknesses. In the interests of expediency, and with the requirement to produce a prudent forecast, the Demand Group considers the recommendations made best meet the requirements of their brief.

### 5.2.2 Background

The Demand Group has been tasked with building on the work of previous National Winter Groups in developing a prudent estimate of peak demand for winter 2015 for the North Island, the South Island and New Zealand.

### 5.2.3 Peak Demand Data Set

The demand working group used Transpower’s PI system billing series data.

- Transmission losses are not included and therefore an appropriate allowance must be made when comparing the forecast demand with the generation stack;
- Distribution losses (or losses on the customer side of the GXP) are implicitly included in the data and therefore do not need to be separately provided for;
- This series records the net demand at the GXP therefore the volume of embedded generation dispatched “outside the market” is implicitly included. Embedded generation which is included in the generation stack, such as part of the

generation from Waipori Hydro connected at the Half-way Bush GXP has been added back to the net demand figure;

- Embedded generation that is "market dispatched" is not netted against demand at the GXP and therefore needs to be included in the generation stack;
- This year we have chosen not to make any specific adjustments to allow for the effects of the 2008 electricity savings campaign or the drop in load at Tiwai Point smelter in 2008, 2009 and again through 2012 to 2014;
- Peak demand recorded in 2014 was the lowest for any year since 2005 with ongoing energy efficiency gains and a mild winter two of the chief influences;
- In 2013 there was a significant and permanent reduction in demand at the Norske Skog Tasman pulp and paper mill in Kawerau.

### *5.2.4 Linear Regression*

The Demand Group applied a number of related statistical analysis techniques to the available data set. All of the techniques applied are founded on linear regression to some degree. The techniques can be characterised as top-down, rather than bottom-up, i.e. no attempt was made to estimate peak demand by building the likely demand up from discrete customer classes or activities. In the following sections the North Island data is used, the summary tables above set out the equivalent results for the South Island and the New Zealand data sets.

Linear regression is applied to the annual highest peak data series to test whether the equation generated is a useful means to describe the series (and therefore useful in forecasting the 2015 peak). This technique fits a line to the data series producing what is often referred to as a 'line of best fit" or trend line. This year the line was fitted to data from 2003 to 2014; dropping demand data from the 1997 to 2002 period to allow a better fit to be made in the more recent decade of generally lower growth. A prudent peak demand forecast for 2015 is plotted (blue diamond); the calculation of this value is set out below. Figure 6 displays the result of this analysis.

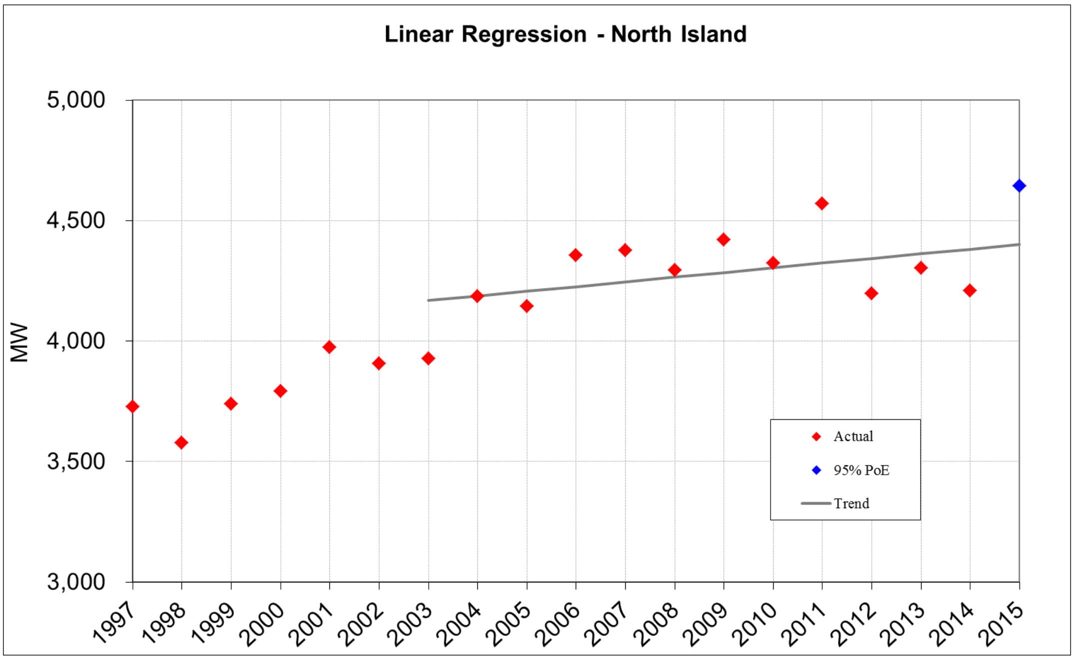


*Figure 6: North Island 10 year peak demand trend*

### 5.2.5 Variation around the Trend Line

After fitting a trend line to the data series, the standard error of the variance between the data series and the trend line is calculated. The standard error is 145 MW.

The Student's t distribution is used to estimate the range of this expected variation for a given confidence level. The Demand Group determined that an appropriate probability of exceedance (PoE) is in the order of 5% or one in twenty years.

### 5.2.6 Prudent Peak Forecast Using Linear regression

The application of linear regression produces a prudent peak forecast as follows:

$$\text{Prudent Peak NI}_{\text{Linear Regression}} = \text{2014 trend line} + \text{standard error} \times t_{(.05,\ 9)}$$
$$= 4{,}401 + 145 \times 1.81$$
$$= 4{,}401.4 + 262.4$$
$$= 4{,}664 \text{ MW}$$

### 5.2.7 Limitations of Linear Regression

The available data set has 18 data points. While this is a relatively small data set it is already difficult to fit one simple linear model satisfactorily through all the years. Fitting to data from 2003 provided a good balance in picking up on both the higher growth seen to 2006 and the flatter peak demand seen since then. Our forecasts thus allow for some return to growth which is to be expected at some stage in the future.

### 5.2.8 Modified Linear Regression

This approach uses linear regression to fit a trend line to the observed peak demand data points since 2010. The linear regression model calculates mean demand in 2014 of 4,220 MW. This mean value is then grown by an assumed growth rate to generate the expected demand for the 2015 year.

As with linear regression approach, the variance around the mean peak demand is calculated using the standard approach to calculating the standard error implicit in the data series multiplied by the appropriate student t factor to give the desired level of confidence.

### 5.2.9 Modified Linear Regression (Medium Growth)

The 2014 expected peak is grown by 2.3% (per EC 2010 SoO expected forecast) to give an expected forecast of 4,483 MW for 2015. The standard error was then applied to generate a prudent peak as follows:

$$\text{Prudent Peak}_{\text{Mod Med Growth}} = \text{P50 forecast}_{2013} + \text{standard error} \times t_{(.05,\ 12)}$$
$$= 4{,}483 + 145 \times 1.81$$
$$= 4{,}483 + 263$$
$$= 4{,}746 \text{ MW}$$

Figure 7 illustrates this approach and the forecast generated.

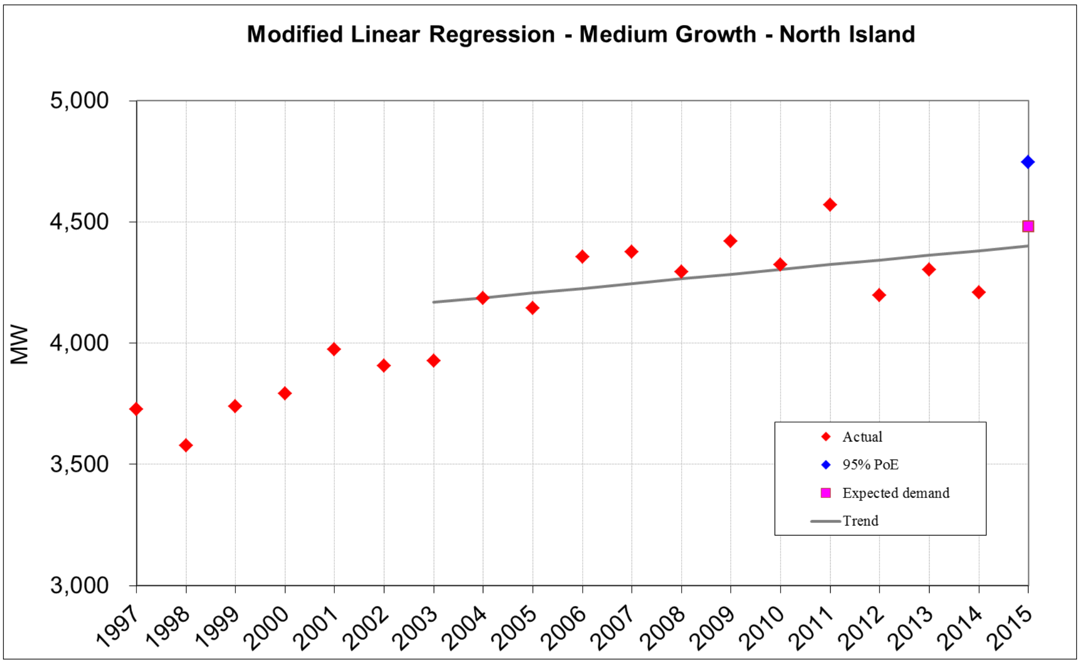


*Figure 7: North Island modified linear regression forecast*

### *5.2.10 Modified Linear Regression (High Growth)*

Here the 2013 expected peak is grown by 2.5% (per EC 2010 SoO Prudent forecast growth rate) to give a forecast of 4,493 MW for 2015. The standard error was then applied to generate a prudent peak forecast of 4,755 MW.

### *5.2.11 Weaknesses of Modified Linear Regression Model*

This methodology addresses the inability of a linear regression model to recognise emerging trends, by replacing the linear model with a growth rate to generate the 2015 expected forecast. The peak demand growth from the EC's 2010 Statement of Opportunities was used as the growth rate in the 2015 year. Although this forecast is now 5 years old it has been retained as its view is for higher growth than more recent forecasts produced by MBIE (Ministry of Business, Innovation and Employment) in Energy Outlook 2013 and by Transpower for its Annual Planning Report 2014 (April 2014).

### *5.2.12 Losses*

The group has endeavoured to gain an understanding of transmission losses at system peak. The group recognises that losses vary significantly between normal and abnormal operations of the grid. The load flow analysis conducted by the System Operator suggests an allowance of 148 MW for losses at system peak is appropriate for the North Island and 110 MW for the South Island.

### *5.2.13 Demand Step Changes*

The methods outlined have no ability to identify or predict step-changes in demand. In previous years the impact of the Christchurch earthquake and the reduced production from Norske Skog's Kawerau pulp & paper mill had been seen to supress demand growth. The 2014 peak demand was again subdued and was in fact the lowest year's peak since 2006. This was seen despite strong economic growth being recorded in New Zealand and a boost to the population with near record net migration. It seems the mild winter and ongoing energy efficiency gains must have countered those growth drivers.

Solar PV installations have grown strongly in 2014 but there is little impact assumed on winter peak demand which generally occurs in the dark half-hour from 5.30pm on winter evenings.

## 5.3 Generation Workstream

### *5.3.1 Introduction*

The **Generation workstream** report covers the analysis of generation available to cover the prudent system peak for 2015. The report establishes a view of generation availability at peak for both the North and South Islands. These generation figures will be evaluated against the forecasts produced by the Demand workstream.

The objective of this work is to define a generation availability stack to ascertain whether there is likely to be sufficient generation to cover the system demand requirements (energy, reserve and frequency keeping) for the forecast 2015 peak winter demand. The period considered for analysis is the Southern Hemisphere winter months of June to August.

The approach used in identifying available generation is similar to that used in previous years.

Each of the generators have provided their generation values and time series data for stations and blocks across New Zealand. For generation with a variable output due to fuel constraints, the levels of expected generation have been taken at a 10% confidence level. That is, the level of generation that has historically been available 90% of the time, during the winter evening peak. Varying amounts of historical data are used as appropriate for the generation type.

Noting the varying types of generation within the New Zealand power system, the Generation Group agreed on a classification system for generation type. The classification type is representative of the physical nature of the generation.

The “generation” capability stack includes:

- Thermal
- Geothermal
- Hydro Storage
- Hydro Run-of-river (variable)
- Wind (variable)
- Co-generation (variable)
- Uncommitted fast (available within three hours)
- Uncommitted slow (requires more than three hours for a “cold start”)
- HVDC transfer – North Island only

In addition, the North and South Island generation stacks include:

- Interruptible load sustained instantaneous reserves (IL SIR; represented as a positive generation figure as this is available to cover the island reserve requirement)

From NWG 2014, generation SIR is not explicitly included in the generation stack. This is because plant capacity is instead represented as the lower of maximum continuous rating (MCR) and maximum continuous output (MCO) in asset capability statement (ACS), unless advised otherwise by the asset owner. This is a departure from previous years, which used average offered quantities of energy and reserve separately.

HVDC northward transfer capacity has been treated as an addition to the generation stack for the North Island but not as a subtraction from the South

Island generation stack (see 5.4.2). This is because North and South Island demand peaks are generally not coincident. It is assumed here that both Pole 2 and Pole 3 will be available from June to August.

Notified outages (from POCP) were evaluated and applied to generation capacity where appropriate for the relevant time periods; these are outages occurring on weekdays and which cover part or all of the evening peak period of 17:30-19:30.

Taking into consideration all of the above, the data is converted into two generation availability stacks; one for each island. These stacks are detailed in section 5.4.

### *5.3.2 Scenarios*

The Generation Group also examines four additional scenarios regarding generation availability detailed in Table 6.

- **N-G:** Loss of largest generating unit
- **N-1:** Loss of HVDC Pole 3
- **N-G-1:** Outage of largest generating unit and loss of HVDC Pole 3
- **Gas supply outage:** Loss of all gas-fired generation due to a Critical Gas Contingency

*Table 6: Scenario overview*

| Scenario | Island | MW loss | Comment |
|---|---|---|---|
| **N-G** | NI | 400 | Approximately Huntly 5 or Otahuhu B |
| **N-1** | | 612 | Assume maximum HVDC transfer received of 528 MW (Pole 2, ½ hour overload) |
| **N-G-1** | | 1012 | Sum of the above |
| **Gas supply outage** | | 1017 | The sum of Otahuhu B, Southdown, Huntly U5 and Huntly U6 MW capacities (TCC is already removed from the 2015 analysis) |

The gas supply outage scenario assumes the Critical Gas Contingency 1a and 1b curtailment bands (as defined in the Gas Governance Regulations 2008) are triggered. These bands include all gas-fired generation connected to the main network. However, previous studies by the System Operator have identified that with sufficient warning it is feasible for the older Huntly units to be switched to coal in time to mitigate a gas outage. The Stratford and McKee peaking generators can operate independently from main gas network using gas storage at Contact Energy’s Ahuroa facility, and local McKee field gas respectively. For this reason they are not removed from the generation stack for this scenario.

These scenarios represent progressively more serious disruptions to the power system and are used to test assumptions and the robustness of results.

### *5.3.3 Provenance of Data and Methodology*

Generators across New Zealand have provided their generation values and time series data. Generation values provided are typically for generators which are operated by fuel or non-varying profile i.e. thermal, large hydro storage, geothermal and a number of the co-generation plants.

Time series data are used for generators that have strong reliance on weather or have a varying profile, i.e. hydro run-of-river and wind turbines. For variable generation, the Generation Group utilised the time series data to obtain prudent

10th percentile values. This is the level of generation that is expected to be available 90% of the time.

Other than generation information, the Generation Group also evaluates interruptible load offers at the 10th percentile. This is included as it is available to cover the system reserve requirement and free up spinning reserve to provide energy instead.

Planned outage information is obtained from POCP and used to offset the total generation available for each generation type. This information is attached in the appendix section 5.6.

### 5.3.4 Thermal

Table 7 provides breakdown of thermal generation values provided by Contact, MRPL and Genesis. It excludes thermal generators that are categorised as uncommitted (fast or slow). Uncommitted generation figures will be covered in section 5.3.10.

*Table 7: Thermal generation overview*

| Generators | MW | Comment |
|---|---|---|
| Stratford peakers | 208 | |
| Stratford TCC | 0 | On standby during winter 2015 due to reduced contracted fuel quantities |
| Otahuhu B | 386 | |
| Southdown | 178 | An additional 52 MW is assumed to be uncommitted fast |
| Huntly 1-4 | 250 | 1 unit, 1 is assumed to be uncommitted slow |
| Huntly 5 | 403 | |
| Huntly 6 | 50 | |
| Whirinaki | 156 | |
| **Total Thermal** | **1673** | |

### 5.3.5 Geothermal

Contact and Mighty River Power have provided generation values for geothermal plants as shown in Table 8 below.

*Table 8: Geothermal generation overview*

| Generators | MW | Comment |
|---|---|---|
| Poihipi | 51 | |
| Ohaaki | 45 | As advised by Contact Energy |
| Wairakei | 125 | Reduced output post Te Mihi commissioning |
| Mokai | 114 | MRP and TPC |
| Rotokawa | 30 | Embedded generator |
| Tauhara | 26 | |
| Kawerau | 103 | |
| Nga Awa Purua | 134 | Capacity reduced in 2014 due to turbine damage |
| Onepu | 39 | |
| Ngatamariki | 82 | |
| Te Mihi | 158 | |
| **Total Geothermal** | **919** | |

### 5.3.6 Hydro Run-of-river and Co-generation

*North Island:*

The Generation Group aggregated hydro run-of-river and some of the co-generation time series data to obtain a 10$^{th}$ percentile value. The time series data only considers weekdays, trading periods 34 to 38 (16:30 to 19:00), and covering the months of June to August from 1999 to 2014. Static values for Kinleith (40 MW), Whareroa (64 MW) and Te Rapa (45 MW) are as provided to System Operator and are added to obtain the total quantity.

Hydro run-of-river generators in the North Island are Kaimai, Patea, Matahina, Wheao, Mangahao, Aniwhenua and Rangipo. Co-generators in the North Island that are aggregated together in the series are Glenbrook and Kapuni.

Table 9 shows the collective value of 332 MW at the 10$^{th}$ percentile.

*Table 9: North Island hydro run-of-river and co-generation overview*

| Percentile | Aggregate NI Hydro Run-of-river and Co-generation (MW) | Aggregate MW with KIN, WAA, TRC (+149 MW) |
|---|---|---|
| 0% | 103 | 252 |
| **10%** | **183** | **332** |
| 20% | 199 | 348 |
| 30% | 215 | 364 |
| 40% | 237 | 386 |
| 50% | 257 | 406 |
| 60% | 273 | 422 |
| 70% | 289 | 438 |
| 80% | 313 | 462 |
| 90% | 344 | 493 |
| 100% | 534 | 683 |

*South Island:*

Hydro run-of-river generators in the South Island are Branch River, Kumara, Highbank and Patearoa. The base data only considers weekdays, trading periods 34 to 38 (16:30 to 19:00), and covering the months of June to August from 1999 to 2014. Table 10 shows the generation cumulative distribution including a 10$^{th}$ percentile value of 26 MW.

Table 10: South Island hydro run-of-river overview

| Percentile | Aggregate SI Hydro Run-of-river (MW) |
|---|---|
| 0% | 0 |
| **10%** | **26** |
| 20% | 29 |
| 30% | 31 |
| 40% | 34 |
| 50% | 35 |
| 60% | 42 |
| 70% | 48 |
| 80% | 53 |
| 90% | 56 |
| 100% | 110 |

### *5.3.7 Hydro Storage*

*North Island:*

Table 11 below summarises generation values provided by Genesis and Mighty River Power. Total hydro storage capacity in the North Island is 1427 MW.

Table 11: North Island hydro storage overview

| Generators | MW | Comment |
|---|---|---|
| Waikato River | 1059 | Includes 9 stations |
| Waikaremoana | 128 | Includes 3 stations |
| Tokaanu | 240 | |
| **Total Hydro Storage** | **1427** | |

*South Island:*

Total Hydro storage in South Island is 3449 MW as shown in Table 12.

*Table 12: South Island hydro storage overview*

| Generators | MW | Comment |
|---|---|---|
| Roxburgh | 280 | 40 MW is assumed to be uncommitted fast |
| Clyde | 400 | 64 MW is assumed to be uncommitted fast |
| Waitaki River | 1538 | Includes 6 stations |
| Manapouri | 800 | |
| Tekapo | 176 | Stations A & B |
| Cobb | 32 | |
| Coleridge | 39 | |
| Waipori | 80 | |
| **Total Hydro Storage** | **3345** | |

### 5.3.8 Wind

*North Island:*

Te Apiti, West Wind, Te Uku and Tararua wind farm generation values are aggregated for 2014 for the months of June to August, covering trading periods 34 to 38. The 10th percentile value is 43 MW as shown in Figure 8 below. Mill Creek has not been included for NWG 2015.

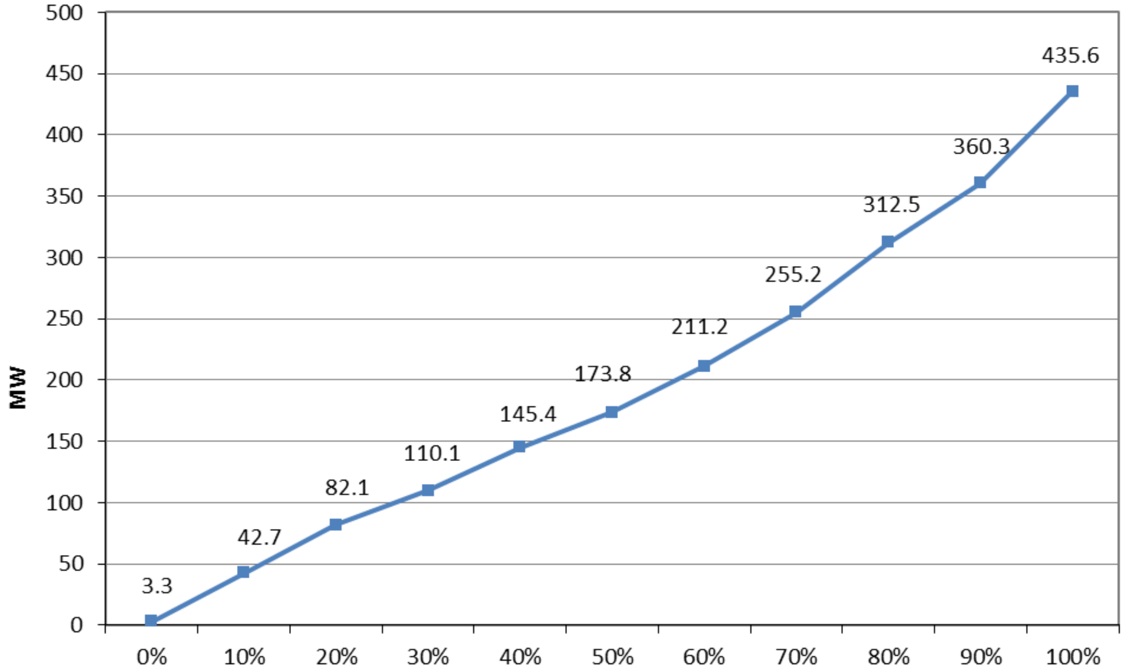


*Figure 8: Aggregate North Island wind farm generation by percentile*

*South Island:*

White Hills and Mahinerangi wind farm data has been analysed for the months of June to August 2014 for trading periods 34 to 38. The 10th percentile value is 0 MW as shown in Figure 9 below.

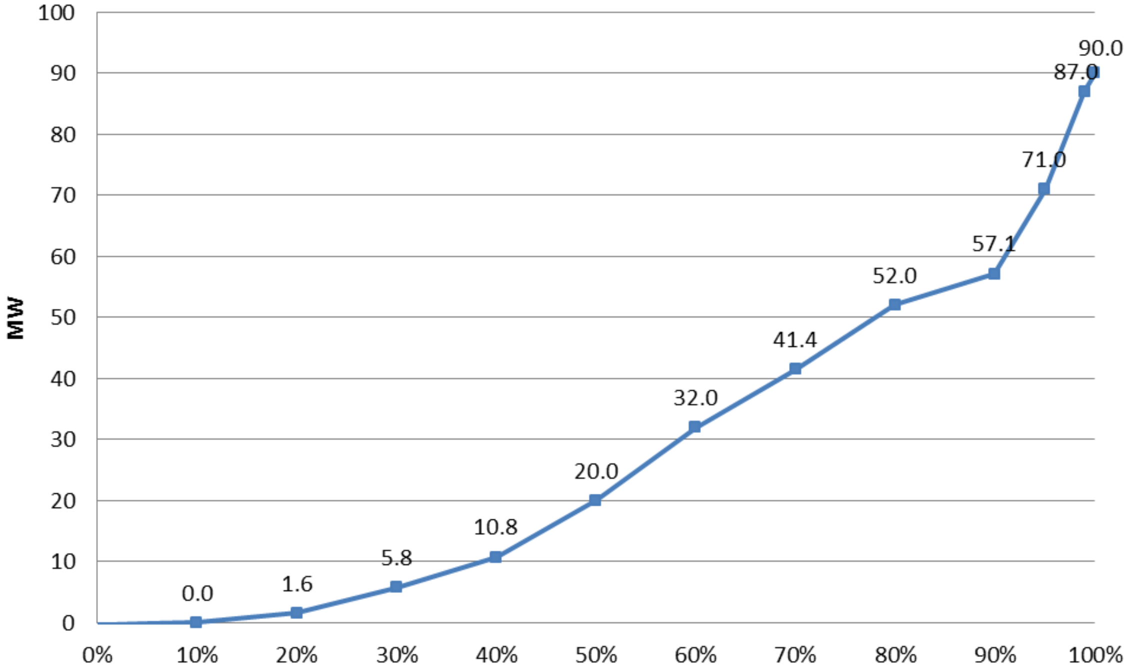


*Figure 9: Aggregate South Island wind farm generation by percentile*

### 5.3.9 Sustained Instantaneous Reserves

Interruptible load sustained instantaneous reserve offers have been analysed for June to August 2014, covering trading period 34 to 38. Figure 10 below shows the resulting North Island 10th percentile value of 156 MW.

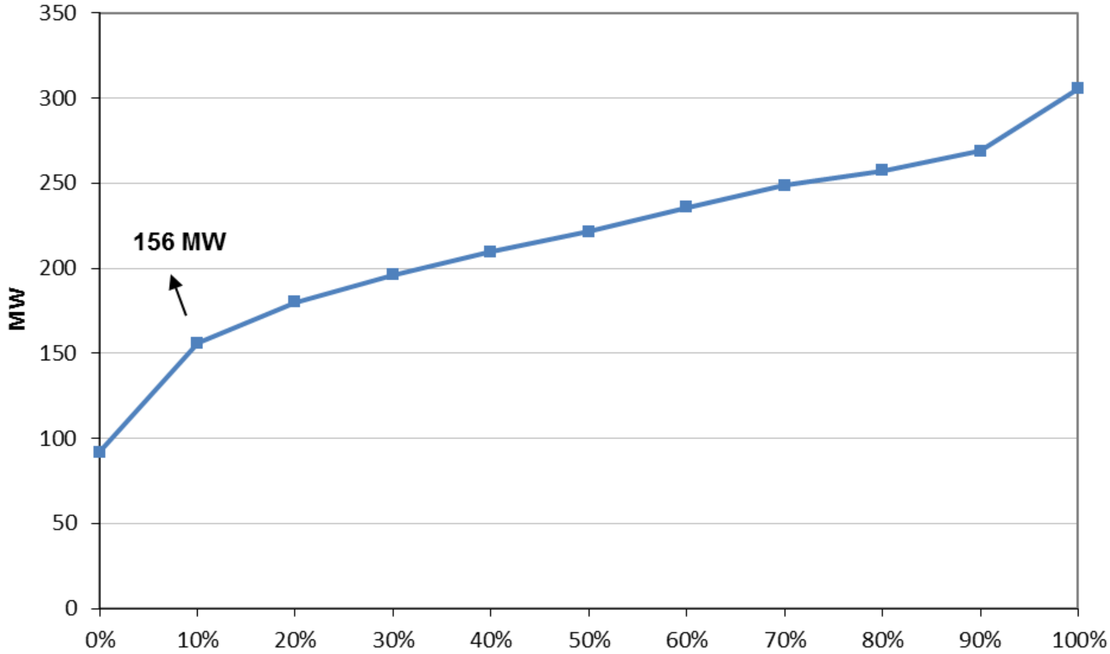


*Figure 10: Aggregate North Island sustained interruptible load by percentile*

### 5.3.10 Uncommitted Fast and Slow

Table 13 below summarises uncommitted plant figures as assumed in the NWG analysis. Uncommitted fast is capable of starting up with 3 hours, while uncommitted slow requires between 3 and 12 hours before it is available to generate. Both categories rely on appropriate market signals in order to be available to meet peak demand.

*Table 13: Uncommitted generation overview*

| Generators | Fast | Slow | Comment |
|---|---|---|---|
| Huntly 1 - 4 | | 250 | 1 unit |
| Southdown | 52 | | E105 only |
| Roxburgh | 40 | | |
| Clyde | 64 | | |
| **Total** | **156** | **250** | |

### 5.3.11 Reserve and Frequency Keeping Requirements

For the base case, 612 MW of sustained reserve is required to cover full HVDC transfer (1140 MW received) minus the risk subtractor (528 MW).

Reserve values for the additional scenarios are dependent on post-event HVDC status, as shown in the table below.

For example, in the N-1 scenario reserve is needed to cover the remaining received HVDC transfer. The losses for 550 MW of HVDC transfer sent utilising only Pole 2 are calculated to be 22 MW, yielding 528 MW received in the North Island. This transfer can be sustained as an overload capacity for up to 30 minutes and must be covered 1-for-1 by sustained reserves to keep the power system in a secure state.

*Table 14: Scenario post-contingent reserve requirements*

| Scenario | Island | Reserve required (MW) | Comment |
|---|---|---|---|
| **N-G** | NI | 612 | HVDC bipole is the risk setter |
| **N-1** | | 528 | HVDC Pole 2 is the risk setter |
| **N-G-1** | | 528 | HVDC Pole 2 is the risk setter |
| **Gas supply outage** | | 612 | HVDC bipole is the risk setter |

The normal contingent event (CE) reserve requirement in the South Island is set to 121 MW, to cover the maximum output of a single Manapouri unit.

Frequency keeping is assumed to be 20 MW in the North Island and 10 MW in the South Island, in line with standard operation early in 2015. The frequency keeping band is modelled as an equivalent (potential) increase to the instantaneous peak load.

### *5.3.12 Generation Outages*

The Generation Group determined the planned MW loss between June and August 2015 from generation outage information notified in POCP (as of 11 February 2015). Table 1 and Table 2 in section 2 summarise the planned outages that will contribute to the aggregate deduction of generation from the stack.

The following methodology was used to produce these figures (equivalent to NWG 2014):

- Outages not extending over the evening peak period of 17:30 to 19:30 are not included for the day
- Highest coincident outage values are provided by week but this may not extend for the whole week
- The evening peaks on weekends are not considered because load is typically significantly lower than on weekdays

### *5.3.13 Summary of Variable Generation*

Table 15 and Table 16 give an indication of the change in capacity available as affected by variable generation stack components. From the North Island table it can be seen that the 50th percentile value indicates 263 MW extra relative to the 10th percentile value. Likewise, an additional 27 MW is observed for South Island. This provides a significant degree of confidence in the variable generation values used for both islands.

*North Island:*

*Table 15: North Island variable generation summary*

| Percentile | Hydro Run of River & Co-gen | Wind | IL SIR | Total Variable MW | MW change from 10% base case |
|---|---|---|---|---|---|
| 0% | 252 | 3 | 92 | 347 | -184 |
| 10% | 332 | 43 | 156 | 531 | 0 |
| 20% | 348 | 82 | 180 | 610 | 79 |
| 30% | 364 | 110 | 196 | 670 | 139 |
| 40% | 386 | 145 | 210 | 741 | 210 |
| 50% | 406 | 174 | 222 | 802 | 271 |
| 60% | 422 | 211 | 236 | 869 | 338 |
| 70% | 438 | 255 | 249 | 942 | 411 |
| 80% | 462 | 312 | 257 | 1031 | 500 |
| 90% | 493 | 360 | 269 | 1122 | 591 |
| 100% | 683 | 436 | 305 | 1424 | 893 |

*South Island:*

*Table 16: South Island variable generation summary*

| Percentile | Hydro Run of River | Wind | Total Variable MW | MW change from 10% base case |
|---|---|---|---|---|
| 0% | 0 | 0 | 0 | -26 |
| 10% | 26 | 0 | 26 | 0 |
| 20% | 29 | 2 | 31 | 5 |
| 30% | 31 | 6 | 37 | 11 |
| 40% | 34 | 11 | 45 | 19 |
| 50% | 35 | 20 | 55 | 29 |
| 60% | 42 | 32 | 74 | 48 |
| 70% | 48 | 41 | 89 | 63 |
| 80% | 53 | 52 | 105 | 79 |
| 90% | 56 | 57 | 113 | 87 |
| 100% | 110 | 90 | 200 | 174 |

Figure 11 displays this information graphically.

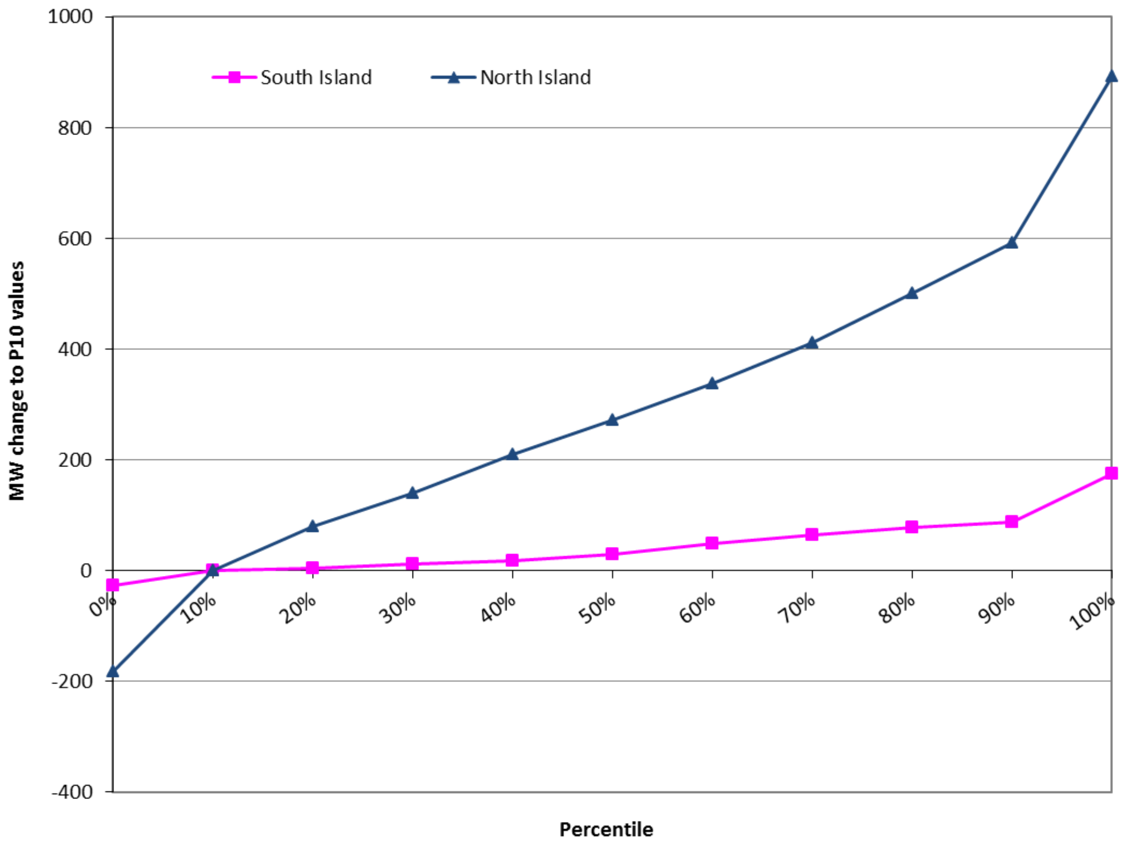


*Figure 11: MW change in variable generation relative to P10*

## 5.4 Generation Stacks

Figure 1 and Figure 2 in section 2 consolidate all available generation and equivalent reserve based on the analyses described above. The generation profile is presented on a week-by-week basis.

For each week, planned generation outages have been removed from the relevant generation type. The HVDC link is assumed to be running North at its maximum capacity of 1200 MW (1140 MW received).

For the North Island, "Demand P95" refers to the summation of total forecast 95$^{th}$ percentile load (4679 MW), losses (148 MW), frequency keeping (20 MW) and intra-trading period variability (39 MW). For the South Island, "Demand P95" refers to the summation of total forecast 95$^{th}$ percentile load (2215 MW), losses (110 MW), frequency keeping (10 MW) and intra-trading period variability (13 MW).

### *5.4.1 Effects of HVDC Transfer*

The received North flow on the HVDC link is counted as a positive generation figure in the North Island generation stack. The size of the risk of the loss of a single pole is calculated as the received bipole transfer minus the smaller of the individual pole 30 minute overload capacities (received). This HVDC risk subtractor for North transfer is normally 528 MW when all HVDC equipment is in service. In such circumstances, when the received transfer exceeds 928 MW (400 MW for a large thermal unit + 528 MW) the HVDC link will be the North Island risk setter and additional transfer must be met 1-for-1 by sustained reserves. In effect, this means is that HVDC transfer over 928 MW received has a zero-sum effect on the North Island generation stack.

This is a very high level of HVDC transfer that may not eventuate in reality. However, for the purposes of the NWG analysis there is a net zero effect on the resulting capacity margin. Therefore, the assumption is effectively for full HVDC availability over winter evening peaks.

### *5.4.2 North and South Demand Peak Coincidence*

To verify that the minimum in South Island generation available for HVDC transfer northwards from the twin peaks analysis should not be used as a limiting factor in the North Island generation stack, the timing of island demand peaks in the last six years has been determined. Table 17 below shows no identified coincident demand peaks. In addition, prior NWG analysis back to 2000 found only one year in which the island demand peaks were coincident. This supports the use of full HVDC transfer for the North Island twin peaks analysis.

*Table 17: Historical island demand peak dates and trading periods*

| | SI demand peak | | NI demand peak | |
|---|---|---|---|---|
| *Year* | *Date* | *Trading period* | *Date* | *Trading period* |
| 2014 | 28-Jul | 16 | 22-Aug | 16 |
| 2013 | 20-Jun | 36 | 15-Jul | 37 |
| 2012 | 6-Jun | 36 | 9-Jul | 37 |
| 2011 | 17-Aug | 36 | 15-Aug | 37 |
| 2010 | 8-Jun | 36 | 28-Jun | 36 |
| 2009 | 29-Jun | 36 | 18-Jun | 37 |

## 5.5 Scenario Results

### 5.5.1 N-G

The North Island reserve requirement is set as 612 MW to cover HVDC transfer. P95 demand refers to the summation of total forecast 95th percentile load (4679 MW), losses (148 MW), frequency keeping (20 MW) and intra-trading period variability (39 MW). The amount of generation lost is approximately equal to the output of a large thermal station such as Huntly 5 or Otahuhu B.

*Table 18: N-G scenario results*

| N-G | 01/06 - 07/06 | 8/06 - 14/06 | 15/06 - 21/06 | 22/06 - 28/06 | 29/06 - 05/07 | 06/07- 12/07 | 13/07 - 19/07 | 20/07 - 26/07 | 27/07 - 02/08 | 03/08 - 09/08 | 10/08 - 16/08 | 17/08 - 23/08 | 24/08 - 30/08 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total generation with 1200 MW DC sent | 5622 | 5550 | 5582 | 5555 | 5587 | 5631 | 5653 | 5592 | 5637 | 5624 | 5678 | 5674 | 5680 |
| Lost generation | -400 | -400 | -400 | -400 | -400 | -400 | -400 | -400 | -400 | -400 | -400 | -400 | -400 |
| Reserve post-event | -612 | -612 | -612 | -612 | -612 | -612 | -612 | -612 | -612 | -612 | -612 | -612 | -612 |
| Total generation remaining | 4610 | 4538 | 4570 | 4543 | 4575 | 4619 | 4641 | 4580 | 4625 | 4612 | 4666 | 4662 | 4668 |
| P95 demand total | 4885 | 4886 | 4886 | 4886 | 4886 | 4886 | 4886 | 4886 | 4886 | 4886 | 4886 | 4886 | 4886 |
| **Surplus/Deficit** | **-276** | **-348** | **-316** | **-343** | **-311** | **-266** | **-245** | **-305** | **-261** | **-274** | **-220** | **-223** | **-217** |

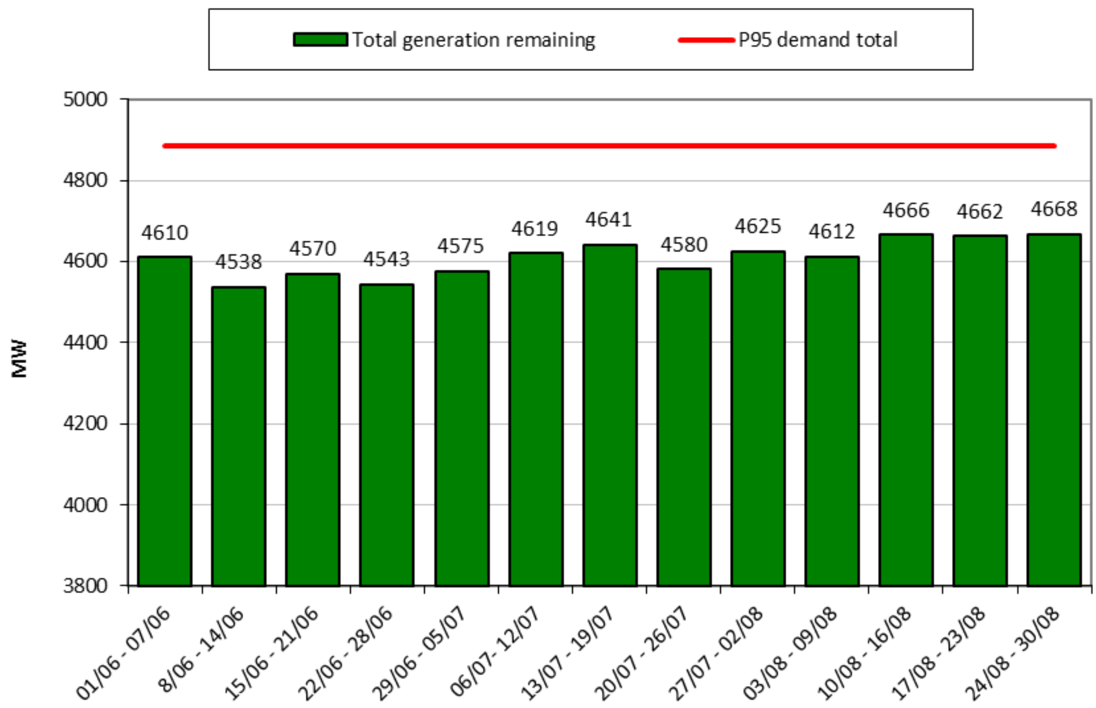


*Figure 12: N-G scenario generation vs. demand*

### *5.5.2 N-1*

The North Island reserve requirement is set as 528 MW to cover Pole 2. The amount of HVDC transfer lost is equal to the pre-event bipole transfer received (1140 MW) minus the overload capacity of Pole 2 (528 MW).

*Table 19: N-1 scenario results*

| N-1 | 01/06 - 07/06 | 8/06 - 14/06 | 15/06 - 21/06 | 22/06 - 28/06 | 29/06 - 05/07 | 06/07- 12/07 | 13/07 - 19/07 | 20/07 - 26/07 | 27/07 - 02/08 | 03/08 - 09/08 | 10/08 - 16/08 | 17/08 - 23/08 | 24/08 - 30/08 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total generation with 1200 MW DC sent | 5622 | 5550 | 5582 | 5555 | 5587 | 5631 | 5653 | 5592 | 5637 | 5624 | 5678 | 5674 | 5680 |
| Lost generation | -612 | -612 | -612 | -612 | -612 | -612 | -612 | -612 | -612 | -612 | -612 | -612 | -612 |
| Reserve post-event | -528 | -528 | -528 | -528 | -528 | -528 | -528 | -528 | -528 | -528 | -528 | -528 | -528 |
| Total generation remaining | 4482 | 4410 | 4442 | 4415 | 4447 | 4491 | 4513 | 4452 | 4497 | 4484 | 4538 | 4534 | 4540 |
| P95 demand total | 4886 | 4886 | 4886 | 4886 | 4886 | 4886 | 4886 | 4886 | 4886 | 4886 | 4886 | 4886 | 4886 |
| **Surplus/Deficit** | **-404** | **-476** | **-444** | **-471** | **-439** | **-394** | **-373** | **-433** | **-389** | **-402** | **-348** | **-351** | **-345** |

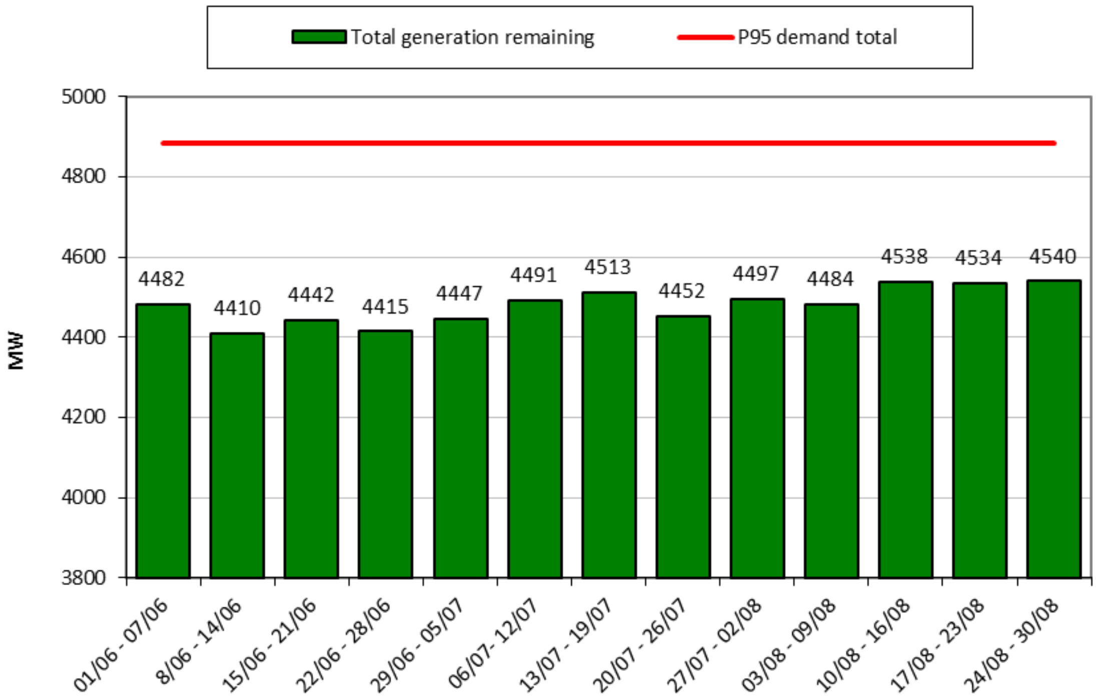


*Figure 13: N-1 scenario generation vs. demand*

### *5.5.3 N-G-1*

The North Island reserve requirement is set as 528 MW to cover Pole 2. A large thermal outage of 400 MW and a coincident Pole 3 trip leads to a total of 1012 MW lost.

*Table 20: N-G-1 scenario results*

| N-G-1 | 01/06 - 07/06 | 8/06 - 14/06 | 15/06 - 21/06 | 22/06 - 28/06 | 29/06 - 05/07 | 06/07- 12/07 | 13/07 - 19/07 | 20/07 - 26/07 | 27/07 - 02/08 | 03/08 - 09/08 | 10/08 - 16/08 | 17/08 - 23/08 | 24/08 - 30/08 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total generation with 1200 MW DC sent | 5622 | 5550 | 5582 | 5555 | 5587 | 5631 | 5653 | 5592 | 5637 | 5624 | 5678 | 5674 | 5680 |
| Lost generation | -1012 | -1012 | -1012 | -1012 | -1012 | -1012 | -1012 | -1012 | -1012 | -1012 | -1012 | -1012 | -1012 |
| Reserve post-event | -528 | -528 | -528 | -528 | -528 | -528 | -528 | -528 | -528 | -528 | -528 | -528 | -528 |
| Total generation remaining | 4082 | 4010 | 4042 | 4015 | 4047 | 4091 | 4113 | 4052 | 4097 | 4084 | 4138 | 4134 | 4140 |
| P95 demand total | 4886 | 4886 | 4886 | 4886 | 4886 | 4886 | 4886 | 4886 | 4886 | 4886 | 4886 | 4886 | 4886 |
| **Surplus/Deficit** | **-804** | **-876** | **-844** | **-871** | **-839** | **-794** | **-773** | **-833** | **-789** | **-802** | **-748** | **-751** | **-745** |

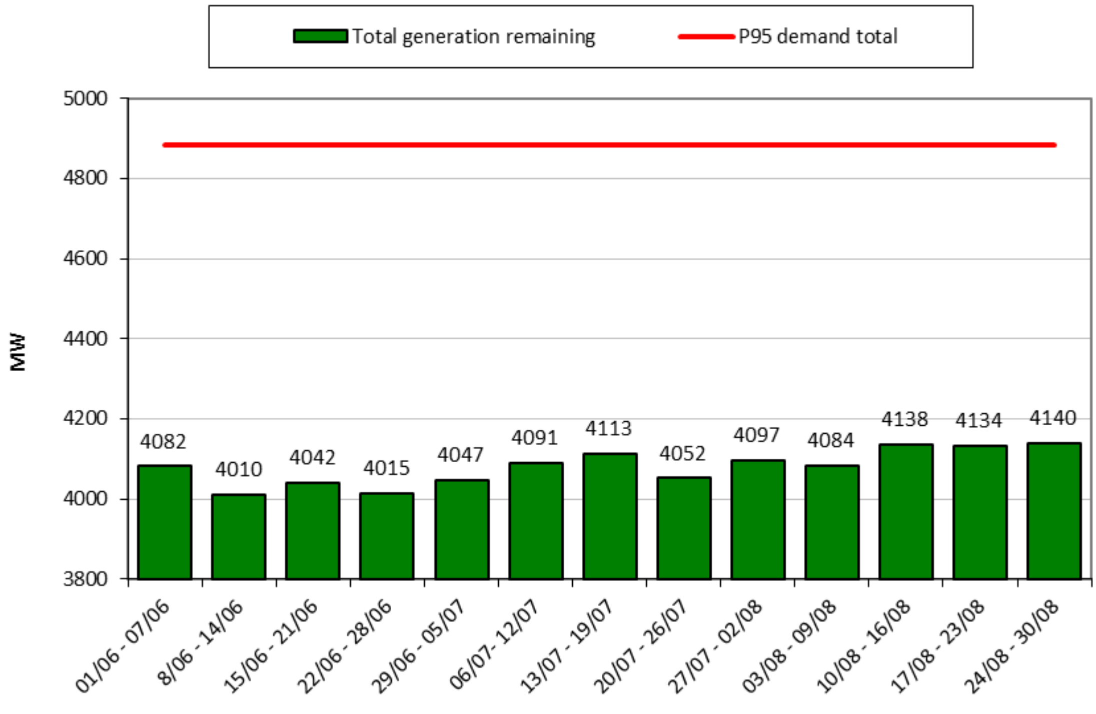


*Figure 14: N-G-1 scenario generation vs. demand*

### 5.5.4 Gas supply outage

The North Island reserve requirement is set as 612 MW to cover the HVDC. The total gas-fired generation capacity affected by the Critical Gas Contingency 1a and 1b curtailment bands is 1017 MW (excludes Stratford peakers, McKee peakers and the two remaining Huntly 1-4 units).

*Table 21: Gas supply outage scenario results*

| Gas supply outage | 01/06 - 07/06 | 8/06 - 14/06 | 15/06 - 21/06 | 22/06 - 28/06 | 29/06 - 05/07 | 06/07- 12/07 | 13/07 - 19/07 | 20/07 - 26/07 | 27/07 - 02/08 | 03/08 - 09/08 | 10/08 - 16/08 | 17/08 - 23/08 | 24/08 - 30/08 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Total generation with 1200 MW DC sent | 5622 | 5550 | 5582 | 5555 | 5587 | 5631 | 5653 | 5592 | 5637 | 5624 | 5678 | 5674 | 5680 |
| Lost generation | -1017 | -1017 | -1017 | -1017 | -1017 | -1017 | -1017 | -1017 | -1017 | -1017 | -1017 | -1017 | -1017 |
| Reserve post-event | -612 | -612 | -612 | -612 | -612 | -612 | -612 | -612 | -612 | -612 | -612 | -612 | -612 |
| Total generation remaining | 3993 | 3921 | 3953 | 3926 | 3958 | 4002 | 4024 | 3963 | 4008 | 3995 | 4049 | 4045 | 4051 |
| P95 demand total | 4886 | 4886 | 4886 | 4886 | 4886 | 4886 | 4886 | 4886 | 4886 | 4886 | 4886 | 4886 | 4886 |
| **Surplus/Deficit** | **-893** | **-965** | **-933** | **-960** | **-928** | **-883** | **-862** | **-922** | **-878** | **-891** | **-837** | **-840** | **-834** |

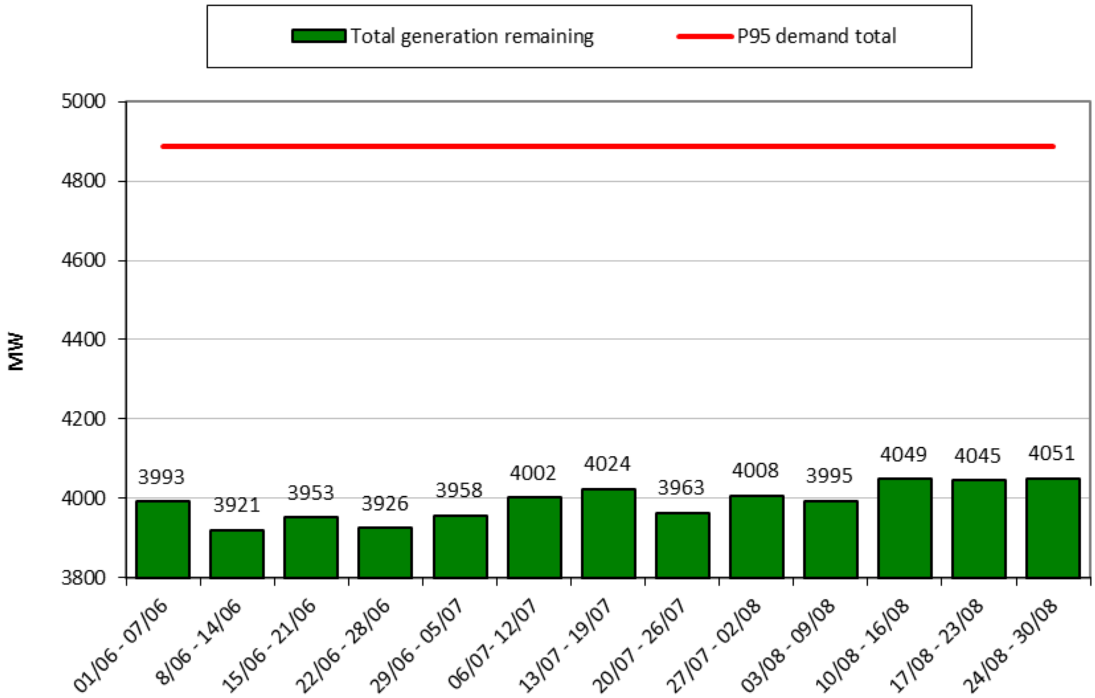


*Figure 15: Gas supply outage scenario generation vs. demand*

### 5.5.5 Scenarios Summary

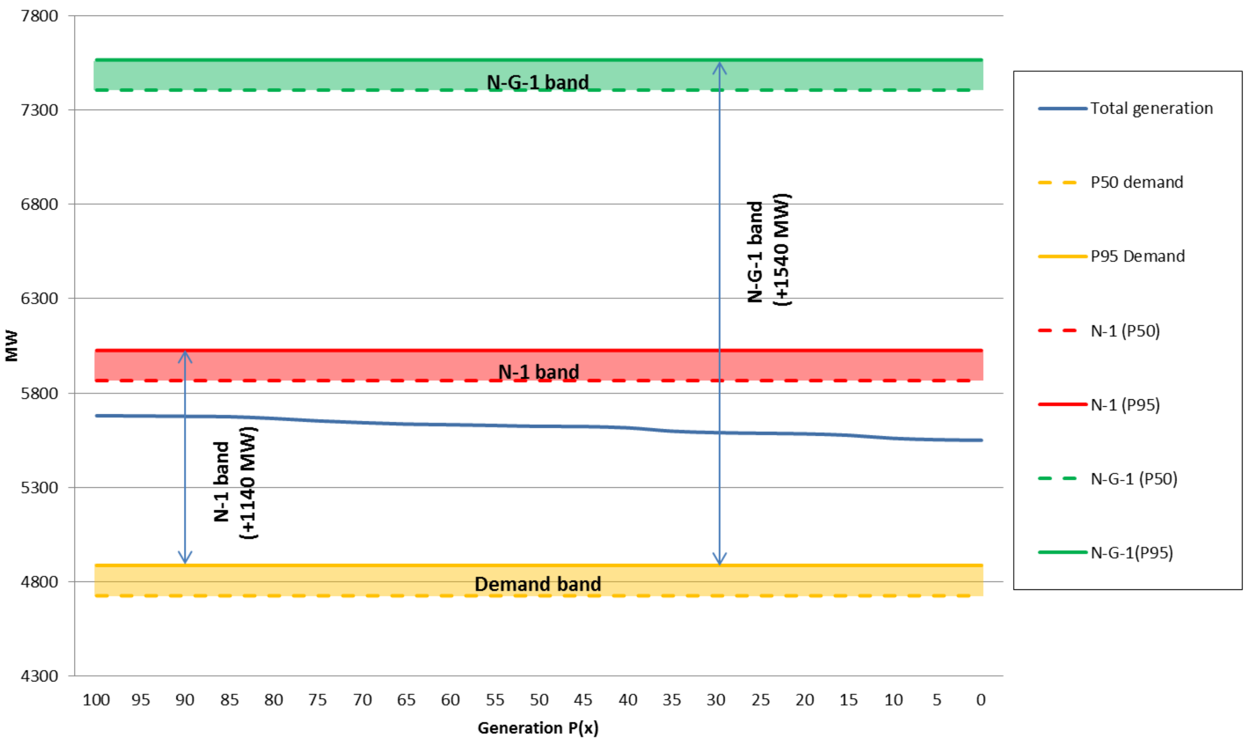


*Figure 16: NWG North Island scenario generation vs. demand comparison*

It can be seen from Figure 16 that at the 50th percentile (average) North Island generation capacity is insufficient to withstand the N-1 or N-G-1 scenarios **and** return to a secure state during winter 2015. This is also true of the N-G and gas supply outage scenarios.

This is not an ideal situation but is mitigated by the fact that the set of conditions implied by these scenarios is very unlikely; i.e. N-G-1 would require maximum coincident outages, peak winter demand, an unplanned outage of a large thermal generator and a Pole 3 trip to coincide. As such, these scenarios are useful for testing assumptions but do not necessarily represent credible or foreseeable risks to the power system.

That being said, each scenario is possible and all would require a Grid Emergency to be declared. Given the size of the generation deficit in each scenario, especially N-G-1 and the gas supply outage scenarios, it is highly likely that demand shedding would be required over winter peaks in order to maintain secure system operation.

For 2015, there is some additional resilience in the system not immediately apparent in the scenarios above. This is achieved by the ability of Contact Energy to transfer contracted gas supply to the Taranaki Combined Cycle station if there is a major unplanned outage at Otahuhu B. The risk of a large thermal station being unavailable over a significant winter evening peak is therefore reduced from a normal year when all large stations are in service.

## 5.6 POCP Outage Information (data extracted on 11 February)

### *5.6.1 North Island Outages Affecting the Generation Stack*

| Outage Block | GIP/GXPs | Gen Type | Start | End | Duration (days) | Owner | Last Modified | Planning Status | MW Loss |
|---|---|---|---|---|---|---|---|---|---|
| MTI_7 | MTI | Hydro | 13/05/2014 7:30 | 30/09/2015 17:00 | 505.40 | Mighty River | 2/12/2014 11:40 | Confirmed | 35.2 |
| KPO_2 | KPO | Hydro | 25/09/2014 7:00 | 3/08/2015 19:00 | 312.50 | Mighty River | 27/01/2015 21:41 | Confirmed | 32 |
| MTI_6 | MTI | Hydro | 13/04/2015 7:00 | 12/06/2015 19:00 | 60.50 | Mighty River | 10/10/2014 20:43 | Confirmed | 35.2 |
| ARI_2 | ARI_Nth | Hydro | 20/04/2015 7:00 | 19/07/2015 19:00 | 90.50 | Mighty River | 8/09/2014 22:35 | Confirmed | 21 |
| MTI_2 | MTI | Hydro | 11/05/2015 8:00 | 10/06/2015 18:00 | 30.42 | Mighty River | 5/12/2014 11:41 | Confirmed | 35.2 |
| TRC_Stn | HAM0331 | Co-Generation | 22/05/2015 7:00 | 26/06/2015 18:00 | 35.46 | Contact Energy | 29/10/2014 18:31 | Tentative | 42 |
| ATI_4 | ATI | Hydro | 25/05/2015 7:00 | 12/08/2015 19:00 | 79.50 | Mighty River | 5/09/2014 11:41 | Confirmed | 18.5 |
| NAP_STN | NAP | Geothermal | 1/06/2015 0:00 | 1/07/2015 0:00 | 30.00 | Mighty River | 26/08/2014 12:19 | Confirmed | 9.4 |
| MTI_3 | MTI | Hydro | 8/06/2015 8:00 | 28/06/2015 18:00 | 20.42 | Mighty River | 5/12/2014 15:18 | Confirmed | 35.2 |
| OKI_Stn | OKI2201 | Geothermal | 9/06/2015 7:00 | 11/06/2015 16:00 | 2.38 | Contact Energy | 9/06/2014 15:23 | Confirmed | 5 |
| MTI_5 | MTI | Hydro | 15/06/2015 7:00 | 30/06/2015 19:00 | 15.50 | Mighty River | 26/08/2014 12:19 | Confirmed | 35.2 |
| OKI_Stn | OKI2201 | Geothermal | 16/06/2015 7:00 | 18/06/2015 16:00 | 2.38 | Contact Energy | 16/06/2014 9:37 | Confirmed | 5 |
| MTI_5 | MTI | Hydro | 29/06/2015 8:00 | 29/07/2015 18:00 | 30.42 | Mighty River | 5/12/2014 15:18 | Confirmed | 35.2 |
| OKI_Stn | OKI2201 | Geothermal | 13/07/2015 8:00 | 20/07/2015 16:00 | 7.33 | Contact Energy | 29/10/2014 18:31 | Tentative | 14 |
| MTI_2 | MTI | Hydro | 20/07/2015 7:00 | 24/07/2015 19:00 | 4.50 | Mighty River | 20/09/2014 11:42 | Confirmed | 35.2 |
| PPI_1 | PPI2201 | Geothermal | 30/07/2015 8:00 | 30/07/2015 22:00 | 0.58 | Contact Energy | 20/10/2014 16:42 | Tentative | 51 |
| ARI_5 | ARI_Sth | Hydro | 3/08/2015 7:00 | 6/08/2015 19:00 | 3.50 | Mighty River | 3/10/2014 11:42 | Confirmed | 27 |
| MTI_1 | MTI | Hydro | 3/08/2015 8:00 | 23/08/2015 18:00 | 20.42 | Mighty River | 5/12/2014 15:18 | Confirmed | 35.2 |
| ARI_8 | ARI_Sth | Hydro | 10/08/2015 7:00 | 13/08/2015 19:00 | 3.50 | Mighty River | 29/01/2015 11:42 | Confirmed | 27 |
| OKI_Stn | OKI2201 | Geothermal | 11/08/2015 8:00 | 11/08/2015 18:00 | 0.42 | Contact Energy | 18/08/2014 10:43 | Confirmed | 4 |
| WRK_Stn | WRK2201 | Geothermal | 12/08/2015 8:00 | 14/08/2015 8:00 | 2.00 | Contact Energy | 29/10/2014 18:31 | Tentative | 10 |
| WRK_12 | WRK2201 | Geothermal | 20/08/2015 4:00 | 20/08/2015 21:00 | 0.71 | Contact Energy | 29/10/2014 18:31 | Tentative | 20 |
| WRK_Stn | WRK2201 | Geothermal | 20/08/2015 8:00 | 21/08/2015 8:00 | 1.00 | Contact Energy | 29/10/2014 18:31 | Tentative | 10 |
| ARA_1 | ARA | Hydro | 26/08/2015 7:00 | 27/08/2015 19:00 | 1.50 | Mighty River | 26/10/2014 7:40 | Confirmed | 26 |

### 5.6.2 *South Island Outages Affecting the Generation Stack*

| Outage Block | GIP/GXPs | Gen Type | Start | End | Duration (days) | Owner | Last Modified | Planning Status | MW Loss |
|---|---|---|---|---|---|---|---|---|---|
| CYD_1 | CYD2201 | Hydro | 11/11/2014 12:01 | 19/06/2015 10:30 | 219.94 | Contact Energy | 21/11/2014 14:34 | Confirmed | 108 |
| MAN3 | MAN | Hydro | 23/03/2015 6:00 | 5/06/2015 18:00 | 74.50 | Meridian | 29/01/2015 2:00 | Confirmed | 121.5 |
| WTK6 | WTK | Hydro | 8/04/2015 6:30 | 22/06/2015 11:30 | 75.21 | Meridian | 16/01/2015 2:00 | Confirmed | 15 |
| OHA6 | OHA | Hydro | 1/05/2015 8:15 | 12/06/2015 8:15 | 42.00 | Meridian | 15/01/2015 2:00 | Confirmed | 66 |
| WTK5 | WTK | Hydro | 25/05/2015 6:30 | 10/07/2015 18:00 | 46.48 | Meridian | 14/01/2015 2:00 | Confirmed | 15 |
| MAN6 | MAN | Hydro | 1/06/2015 6:00 | 26/06/2015 20:00 | 25.58 | Meridian | 2/12/2014 2:00 | Confirmed | 121.5 |
| AVI2 | AVI | Hydro | 1/06/2015 7:00 | 3/08/2015 20:00 | 63.54 | Meridian | 15/01/2015 2:00 | Confirmed | 55 |
| BEN5 | BEN | Hydro | 22/06/2015 8:00 | 26/06/2015 17:00 | 4.38 | Meridian | 23/06/2014 1:58 | Confirmed | 90 |
| MAN2 | MAN | Hydro | 1/07/2015 6:00 | 2/07/2015 20:00 | 1.58 | Meridian | 2/07/2014 1:58 | Confirmed | 121.5 |
| CYD_1 | CYD2201 | Hydro | 9/07/2015 7:00 | 15/07/2015 17:30 | 6.44 | Contact Energy | 3/09/2014 17:14 | Confirmed | 108 |
| OHC13 | OHC | Hydro | 13/07/2015 6:00 | 17/07/2015 18:00 | 4.50 | Meridian | 14/07/2014 1:57 | Confirmed | 53 |
| WTK7 | WTK | Hydro | 13/07/2015 7:00 | 28/08/2015 17:00 | 46.42 | Meridian | 14/01/2015 2:00 | Confirmed | 15 |
| AVI3 | AVI | Hydro | 13/07/2015 7:30 | 25/07/2015 16:00 | 12.35 | Meridian | 14/07/2014 1:57 | Confirmed | 55 |
| MAN7 | MAN | Hydro | 15/07/2015 6:00 | 16/07/2015 20:00 | 1.58 | Meridian | 16/07/2014 1:57 | Confirmed | 121.5 |
| CYD_2 | CYD2201 | Hydro | 16/07/2015 7:00 | 22/07/2015 17:30 | 6.44 | Contact Energy | 3/09/2014 17:14 | Confirmed | 108 |
| CYD_4 | CYD2201 | Hydro | 23/07/2015 7:00 | 29/07/2015 17:30 | 6.44 | Contact Energy | 3/09/2014 17:14 | Confirmed | 108 |
| OHA7 | OHA | Hydro | 27/07/2015 6:30 | 31/07/2015 17:30 | 4.46 | Meridian | 28/07/2014 1:57 | Confirmed | 66 |
| CYD_3 | CYD2201 | Hydro | 30/07/2015 7:00 | 5/08/2015 17:30 | 6.44 | Contact Energy | 3/09/2014 17:14 | Confirmed | 108 |
| OHC15 | OHC | Hydro | 3/08/2015 7:00 | 7/08/2015 18:00 | 4.46 | Meridian | 5/12/2014 2:00 | Confirmed | 53 |
| CYD_3 | CYD2201 | Hydro | 3/08/2015 7:00 | 28/08/2015 17:30 | 25.44 | Contact Energy | 10/12/2014 16:08 | Tentative | 108 |
| ROX_5 | ROX2201 | Hydro | 6/08/2015 7:00 | 9/08/2015 17:30 | 3.44 | 3/09/2014 17:14 | Confirmed | 3.44 | 40 |
| ROX_2 | ROX2201 | Hydro | 10/08/2015 7:00 | 13/08/2015 17:30 | 3.44 | 3/09/2014 17:14 | Confirmed | 3.44 | 40 |
| OHB10 | OHB | Hydro | 10/08/2015 7:00 | 14/08/2015 18:00 | 4.46 | 5/12/2014 2:00 | Confirmed | 4.46 | 53 |
| BEN3 | BEN | Hydro | 10/08/2015 8:00 | 21/08/2015 17:00 | 11.38 | 11/08/2014 1:56 | Confirmed | 11.38 | 90 |
| MAN1 | MAN | Hydro | 11/08/2015 6:00 | 12/08/2015 20:00 | 1.58 | 12/08/2014 1:56 | Confirmed | 1.58 | 121.5 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| AVI1 | AVI | Hydro | 17/08/2015 7:00 | 19/10/2015 21:00 | 63.58 | 15/01/2015 2:00 | Confirmed | 63.58 | 55 |
| ROX_8 | ROX1101 | Hydro | 18/08/2015 7:00 | 21/08/2015 17:30 | 3.44 | 3/09/2014 17:14 | Confirmed | 3.44 | 40 |
| ROX_4 | ROX2201 | Hydro | 26/08/2015 7:00 | 28/08/2015 17:30 | 2.44 | 3/09/2014 17:14 | Confirmed | 2.44 | 40 |