Security and Reliability Council

Thermal generation decommissioning

Reports from Transpower assessing the situation and associated transmission investment options

8 March 2016

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 (SRC) functions under the Electricity Industry Act 2010 (Act) include providing advice to the Electricity Authority (Authority) on security of supply matters.

To this end, the SRC received reporting at its 22 October 2015 meeting that described the impact of thermal generation decommissioning announcement made in late 2015.[1] The SRC's advice to the Authority and the Authority's response are included in the correspondence section of this 15 March 2016 meeting agenda.

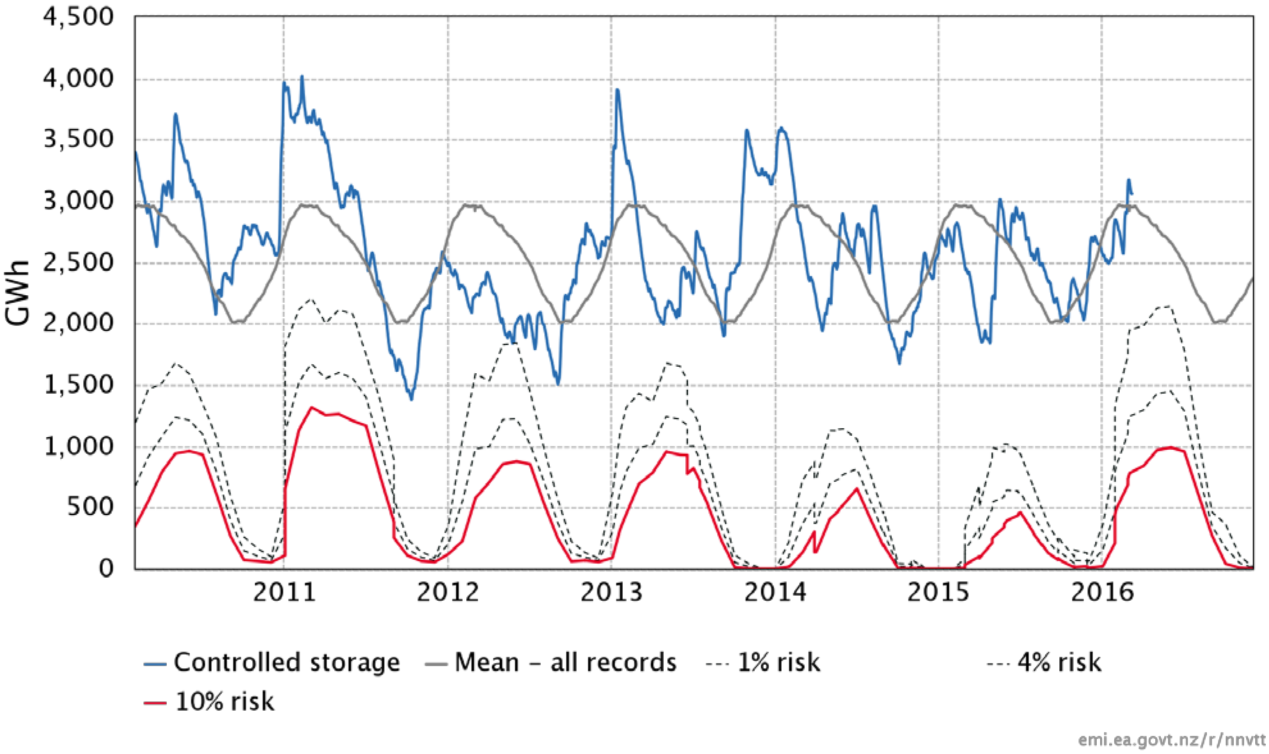
The purpose of this paper is to provide the SRC with a copy of two Transpower reports relating to thermal generation decommissioning and ask questions that may help to establish whether the SRC has advice to offer the Authority. The two reports are:

- *Upper North Island Generation Decommissioning: Summary of investigations stage 1* prepared by the grid owner division of Transpower
- *Security of Supply Analysis: Findings and Implications of Thermal Decommissioning* prepared by the system operator division of Transpower.

Developments since the SRC's 22 October 2015 meeting

Since the 22 October 2015 meeting of the SRC, the system operator has updated the hydro risk curves for 2016. Figure 1 below shows the 2016 hydro risk curves in their historic context.

Figure 1 - New Zealand hydro risk curves, storage and mean storage since 2010



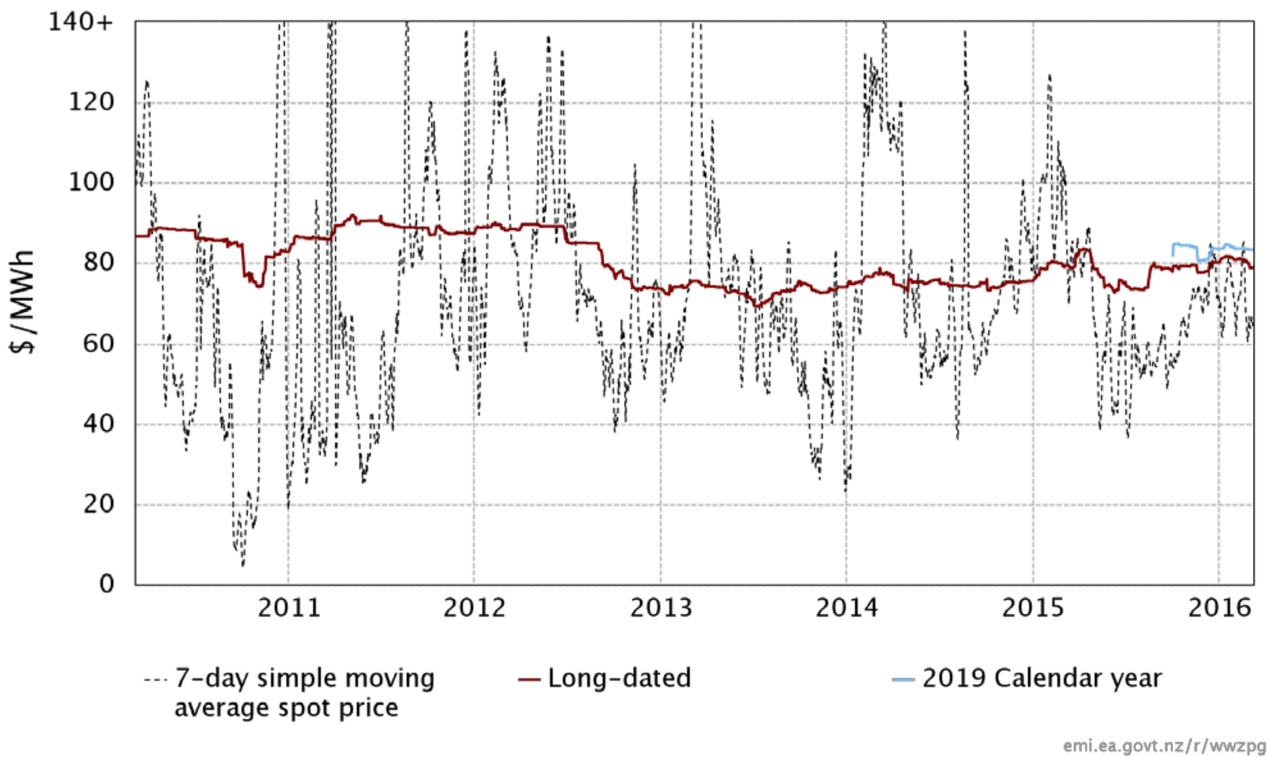
Source: Electricity Authority

[1] The closure announcements related to Otahuhu, Southdown and the Huntly Rankine units owned by Contact Energy, Mighty River Power and Genesis Energy respectively.

Notes: 1. Source data is available from www.emi.ea.govt.nz

The early trend observed at the 22 October 2015 SRC for 2019 forward prices to be very slightly above the long-term average has continued. Figure 2 shows the forward price trends with the 2019 year separated out to highlight the market reaction to the thermal generation decommissioning announcements. The futures prices for 2019 are only slightly elevated, which suggests that the industry believes that either the Huntly Rankine units will stay or alternative sources of supply will occur in time for winter 2019.

Figure 2 - ASX trading for New Zealand electricity futures



Source: Electricity Authority

Notes: 2. Source data is available from www.emi.ea.govt.nz

The SRC's 2 December 2015 advice on thermal decommissioning recommended that the Authority "actively monitor progress…and to have contingency plans in place." Consistent with this, the Authority published a press release on 1 March 2016 that included the statement that:

> "To ensure the correct arrangements are in place for the lead up to 2019 we are currently reviewing how we ensure dry-year security of supply. We have a stress testing scheme that requires firms to monitor and report on the impact high spot prices would have on their finances. We also have a customer compensation scheme that requires retailers to pay $10.50 per week to each customer in the event an official campaign to conserve energy is launched so consumers and not retailers benefit from conservation campaigns. We are looking at these schemes to assess if any refinements need to be made."[2]

[2] From http://www.ea.govt.nz/about-us/media-and-publications/media-releases/2016/1-march-2016-future-proofing-the-electricity-market/

Another development since the SRC's 22 October meeting is the Australian Stock Exchange's announcement that it intends to introduce a cap product to the electricity futures market later in 2016. This is expected to further increase the visibility of future supply risks and is another way for generators and retailers to buy and sell insurance against high spot prices. Cap products will provide another means for parties exposed to spot market prices to communicate how much backup cover the market should provide, whether in the form of backup generation plant or demand-response capability.

The grid owner's paper investigates system constraints that may arise and potential investments to ensure the system meets legislative requirements

The materiality of the thermal generation decommissioning announcements has prompted Transpower, in its capacity as owner of the transmission network, to commission the attached special report. Typically, transmission investigations such as this would fall into the usual cycle of Transpower's *Transmission Planning Report*.

The completed and announced decommissionings amount to over 1000 MW of generation. While this is nationally significant, it is also regionally significant as all three generation sites are north of Huntly. This is why Transpower's report is focussed on the upper North Island (including Huntly).

The grid owner's report has been made available earlier than planned to enable the SRC's consideration, though the secretariat has seen it for the first time on the same day SRC papers were sent. As such, the secretariat has not yet had sufficient time to review and consider the grid owner's report. However, one key observation from the report is that:

> "…the critical assumption for these studies is the location of replacement generation. If significant new generation appears in, or north of, Auckland then the issues are trivial… There are a range of credible generation development areas, and potential transmission constraints vary depending on which of these is or are developed."

Nor has the secretariat had time to review the extensive appendices and whether these are suitable for the SRC's consideration. SRC members should apply some discretion about how much of the appendices warrant their review.

The system operator's paper estimates the likelihood of scarcity pricing or official conservation campaigns occurring under a variety of scenarios

The system operator's thermal generation decommissioning report to the 22 October 2015 meeting of the SRC used the modelling technique used in its annual assessment of security of supply to assess different scenarios.

Subsequent to that meeting, the system operator completed an analysis of thermal generation decommissioning using a different modelling technique intended to answer a question posed by many people: what is the risk? The analysis estimates the risk of scarcity pricing or an official conservation campaign being triggered. The system operator compiled the results of this different modelling technique and published the resulting report in December 2015. That report is attached as Appendix B of this paper.

Transpower representatives will verbally introduce the two papers at the 15 March 2016 meeting

Stephen Jay (General Manager Grid Development) and John Clarke (General Manager System Operations) will provide an oral overview of the two papers. Neither report has been designed with the SRC as the exclusive audience, so the oral overview will seek to focus the SRC's attention on those matters that Transpower consider most relevant for the SRC.

The SRC may wish to consider the following questions.

Q1.	Does the SRC consider that the grid owner's report provides sufficient information for stakeholders to understand the transmission and generation issues arising from thermal generation decommissioning announcements?
Q2.	Does the SRC consider that the system operator's report provides sufficient information for stakeholders to understand security of supply risks arising from thermal generation decommissioning announcements?
Q3.	What further information, if any, does the SRC wish to have provided to it by the secretariat?
Q4.	What advice, if any, does the SRC wish to provide to the Authority?

UPPER NORTH ISLAND GENERATION DECOMMISSIONING REPORT

SUMMARY OF INVESTIGATIONS STAGE 1

Transpower New Zealand Limited
March 2016

Keeping the energy flowing




TRANSPOWER

Transpower New Zealand Limited The National Grid

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1 Executive Summary

This is the third in a series of reports by Transpower to help inform the electricity industry of the potential implications of thermal generation decommissioning, following recent and planned closures of a number of generation plants in the North Island.

The findings in this report indicate that New Zealand's power system may struggle to supply peak loads for the Upper North Island from winter 2020 (under a prudent load forecast) if no new generation were commissioned.

However, it is the view of Transpower that the current energy markets in New Zealand operate well and will provide sufficient investment signals such that sufficient new or refurbished generation will likely be made available in 2019 as required.

The issues identified within this report have been outlined without consideration of how difficult or expensive it may be to resolve them: our next priority is to investigate at a high level the range of potential solutions to these issues so we can provide industry with an understanding of the transmission costs and benefits of a range of new generation locations.

This situation will continue to be monitored closely and updates will be provided as further detailed analysis is completed.

1.1 Background

In 2015, the decommissioning of major generation plants in the Upper North Island (UNI)[1] was announced, including:

- 380 MW Otahuhu combined cycle unit (ceased generation in September 2015)
- 175 MW Southdown generation station (ceased generation at the end of December 2015)
- 500 MW Huntly units 1 and 2 (announced, to be withdrawn from the market in 2018).

This is a significant change to the New Zealand power system and comes on top of the 500 MW already decommissioned at Huntly (units 3 and 4). Consequently, Transpower is undertaking a project to investigate the effects of this decommissioning.

1.2 Process

Transpower has two overall areas of responsibility relating to this power system change. These are:

[1] The region defined as the Upper North Island is defined in Section 1.5 below.

1. short-term (to 2020) – understanding the effects on operability of the existing (and committed) system, and operational procedures that may be required to manage potential constraints, and
2. longer-term (2018 onwards) – investigating system constraints that may arise, and potential investments to ensure that the system meets regulatory and statutory requirements.

The investigations concerning system operability (short-term) are being undertaken by Transpower in its role as System Operator. The System Operator is responsible for day-to-day operation of the transmission system and have Principal Performance Obligations, as defined in the Electricity Industry Participation Code (the Code), which they must meet.

Transpower's Grid Development team is investigating the longer-term constraints. ***It is the investigations into the longer-term constraints that are the topic of this report.***

The first phase of Grid Development's investigations will define the issues. This involves computer-modelling the North Island transmission system, taking the recent and proposed Upper North Island generation decommissioning into account. Projected load growth is modelled, along with a range of new generation scenarios.

The system is tested by modelling a range of credible contingencies (failures of equipment such as circuit outages). This testing is looking for scenarios where the transmission system cannot supply the forecast load without constraints such as overloaded circuits, over or under-voltage and dynamic voltage instability.

Following the announced decommissioning, the largest remaining single generator in the upper North Island region will be Huntly unit 5, at 400 MW. This unit cannot be expected to have 100 per cent availability, so the system was tested for both a single credible contingency (N-1) as well as a single contingency with unit 5 out of service (N-G-1).

There are some precedents[2] for justifying investment based on N-G-1 security, particularly in major load areas such as the Upper North Island.

1.3 Summary of results

The results are broken down into six sub-investigations for this report.

1. Upper North Island reactive support - dynamic analysis
2. Upper North Island reactive support – load flow analysis
3. Thermal constraints between Whakamaru and Auckland
4. Review of existing constraints south of Whakamaru
5. Waikato 110 kV issues
6. High voltage management in the Upper North Island.

Each area is covered comprehensively in separate documents. These are attached as appendices to this report. The following is a summary of findings from the Needs

[2] For example the North Island Grid Upgrade project (2006). See Transpower North Island Supply Upgrade Application.

investigations. We have not considered solutions, so issues are reported without consideration of how difficult or expensive it may be to resolve them.

1. Dynamic voltage stability limits are reduced by the removal of generation in the upper North Island. The investigation found that post-decommissioning, the upper North Island winter N-1 and N-G-1 stability limits will be 2534 MW and 2219 MW respectively. This compares to the actual winter 2015 peak of 2150 MW, and the 2020 Prudent[3] load forecast of 2550 MW. This indicates that the power system will not be able to supply the peak Upper North Island load from 2020 if the last two Rankine units at Huntly are decommissioned.
   An investigation into options to resolve this constraint will be started immediately, and will follow a Major Capex Proposal (MCP) process. In addition, the results of this investigation indicate a possible stability issue in the wider Hamilton area. This will be investigated as part of the next stage of studies.

2. Upper North Island static voltage stability limits may be exceeded when the announced Huntly generation decommissioning goes ahead, unless the existing operating procedures are changed. An investigation into options to resolve this will be undertaken immediately, in conjunction with the dynamic voltage stability investigation. Insufficient dynamic voltage support (rather than static support) is expected to be the first constraint.

3. The timing of thermal constraints between Whakamaru and Auckland depends on the timing and location of replacement generation. For example, new generation in the Wairakei Ring area could create N-G-1 constraints immediately, however new generation in Taranaki will not create constraints between Whakamaru and Auckland in the short term (although it may create constraints outside this area).

4. The 110 kV Bunnythorpe–Mataroa circuit already limits the ability to supply the upper North Island with existing generation from the Wellington and Taranaki regions. There is an investigation underway looking at solutions to this constraint. Even with the Bunnythorpe-Mataroa constraint resolved, thermal N-1 constraints south of Whakamaru will occur as soon as new generation is commissioned in Taranaki or the lower North Island, or HVDC capacity is increased, to replace generation being decommissioned.

5. The Arapuni bus split will remain open, which is a reversal of our previous intention to close this split in 2017. This investigation has gone beyond the Needs stage because it was already an issue we were managing with a development plan[4] in place prior to the generation decommissioning being announced. Further industry consultation on this issue will be initiated in 2016.

[3] Using the Prudent forecast provides a conservative approach to investment timing. The introduction of technologies such as photovoltaics may reduce the load forecast, potentially resulting in deferred investment timing.

[4] See Transpower's website for background information.

6. The management of high voltages in the Upper North Island is not greatly affected by the announcement of the generation decommissioning. This is because it is a light-load issue, which occurs when most generation is turned off anyway. However, our review of this issue has indicated that there may be an economic case for investment and we intend to investigate this in 2016/17.

1.4 Next steps

1.4.1 Upper North Island Voltage Investments

The uncertainty regarding future generation closures and new generation locations creates difficulties in framing grid investment proposals in the absence of clear commitment by industry participants. However, the upper North Island voltage issues are common to the majority of thermal exit scenarios; an investigation to resolve these issues will be started immediately.

We will follow a Major Capex Proposal (MCP) process and will discuss with the Commerce Commission options for compressing the process timeframe.

To progress the MCP process Transpower follows an Investment Approval Process (IAP) which includes four stages:

1. identifying the need
2. identifying options
3. analysing options
4. proposing a preferred solution.

Where transmission investment options are expected to be greater than $20 million, Transpower will submit a MCP to the Commerce Commission for approval.

The process is intended to be transparent to industry participants and includes consultation on the options (at the 'long list' stage) and prior to submitting a proposal. It also includes a request for proposals (RFP) for non-transmission solutions, where appropriate.

This report describes the identified needs (constraints) from step 1. The next stage includes identifying options (long-listing), and will include industry consultation.

Detailed schedules for the project will be determined when the project group is formed.

If an MCP is approved, investments can be delayed or cancelled if the need changes.

1.4.2 Generation located outside of upper North Island

Further investigations on the impact of new generation located in regions outside of the upper North Island, i.e. Whakamaru and south including central North Island, Taranaki, Wellington and the South Island, will be initiated when there is more certainty on future generation investment location, size and timing.

1.4.2 Ongoing investigations

Investigations are already underway to assess options for resolving thermal constraints on Bunnythorpe—Mataroa, retaining the Arapuni bus split and central North Island 110 kV network constraints. These are not expected to require MCP approval.

An investigation into management of high voltages in the upper North Island is expected to commence in late 2016.

1.5 Definition of Upper North Island

Transpower generally uses the description Upper North Island to describe the power system north of Waikato. This includes Glenbrook, Drury and Bombay, and excludes Huntly and Hamilton. However, in this case Huntly generation is integral to the issue. Therefore, for the purpose of this investigation and report, we are including Huntly when referring to the Upper North Island. This is shown in Figure 1 below.

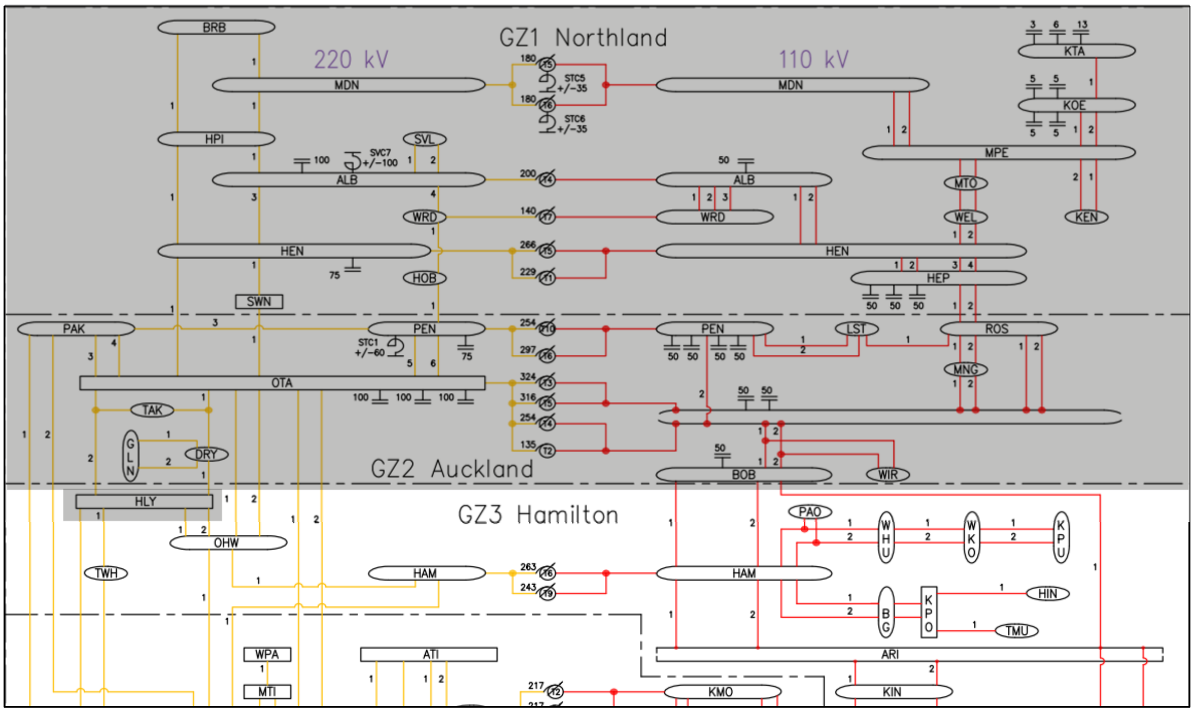

Figure 1: Illustration of Upper North Island transmission system

2 Introduction

Who is Transpower and what is our role in the industry with respect to future developments? Why are we producing this work?

Transpower is the owner and operator of the national grid. We are also the System Operator, responsible for coordinating and managing the transmission of electricity across the national grid.

As the System Operator, Transpower must meet Principal Performance Obligations, as set out in the Electricity Industry Participation Code (the Code).

As the Grid Owner, Transpower has obligations under the Electricity Industry Participation Code with respect to publishing information on grid reliability. Specifically, we must report on whether the grid is reasonably expected to meet the N-1 criterion over the next ten years, and whether we consider there are economic investments that could be made in respect of interconnection assets.

If there is a material change in forecast demand or supply of electricity, Transpower must publish revised information as soon as reasonably practicable.

Under normal circumstances, Transpower meets these obligations via publication of the Transmission Planning Report. The recently-announced generation decommissioning in the Upper North Island results in a material change of electricity supply at Southdown, Otahuhu and Huntly. This has driven the need to undertake the investigations described in this report.

What are the future developments we are investigating?

At the start of 2015, Auckland and Northland installed generation amounted to about 740 MW. Huntly was an additional 940 MW.

There were three major generation decommissioning announcements in 2015.

Mighty River Power’s Southdown generation station is a 175 MW gas-fired generation station located in Auckland. In March 2015, the closure of this station was announced and generation ceased on 31 December 2015.

Contact Energy announced in August 2015 that the 400 MW Otahuhu B power station, located adjacent to Transpower’s Otahuhu substation in Auckland, was to be closed. Generation ceased on 21 September 2015.

In August 2015, Genesis Energy announced its intention to permanently withdraw from the market the last two Rankine coal-burning generation units (units 1 and 2) at Huntly. This followed earlier announcements of the long-term storage and then permanent retirement of units 3 and 4. Each of these units had a nominal output of 250 MW.

The present plan is for withdrawal of units 1 and 2 by December 2018 (unless market conditions change).

The result of these planned and completed closures is that Upper North Island generation reduces from approximately 1680 MW to approximately 610 MW by 2019. The 610 MW includes generation at Huntly, Glenbrook and Ngawha (Kaikohe).

What historical work from the 2015 Transmission Planning Report is relevant to this issue?

Transpower regularly reviews the capacity of the grid to meet future demand and generation scenarios. As part of this work, scenarios that consider very low generation in the Auckland region have been considered, and these are summarised in our 2015 Transmission Planning Report (2015 TPR). The 2015 TPR does not consider generation levels low enough to simulate the announced reduction in generating capacity.

The work in this report builds on the work already done, in particular the existing constraints south of Whakamaru and the Arapuni 110 kV bus split sections.

3 Approach

How is the investigation being staged and what stage are we reporting here?

The approach we are taking to this investigation is based on our major capital investment process. The first stage is identifying and defining any issues (or 'needs').

At this stage we are looking to define a 'need,' which could be a need for capital investment or some alternative such as a non-transmission solution. The aim of this stage is to determine whether an investigation into solutions is justified. This is the stage covered in this report.

The second stage is to investigate solutions to any need that is defined in stage one. This stage generally begins with a long list, followed by a short list, from which a preferred option is selected. It includes a detailed economic assessment of the issue and the short-listed solutions.

For major investigations there will often be industry consultation and feedback at each stage. This aims to ensure general agreement on the credibility of the assumptions used and to get a wide view of potential solutions.

How did we decide what to study?

Through previous planning work, as reported in Transpower's 2015 TPR, we are aware of the general effects of reducing generation in the Upper North Island area.

The areas investigated are a mix of existing issues that may be exacerbated by the generation change (e.g. existing constraints, high voltage management) and issues that we have anticipated for future consideration that may be brought forward (e.g. static and dynamic voltage limits, thermal limits into Auckland).

The approach to generation replacement is the critical assumption.

With the removal of more than 1000 MW of Upper North Island generation, the critical assumption for these studies is the location of replacement generation. If significant new generation appears in, or north of, Auckland then the issues are trivial. However, we are unaware of significant generation investment planned in the Upper North Island area.

There are a range of credible generation development areas, and potential transmission constraints vary depending on which of these is or are developed. To account for this, each study is repeated for a number of generation scenarios. Examples of additional generation, or 'slack bus', locations include Whakamaru, Wairakei, Stratford and Haywards (representing HVDC and/or Lower North Island generation).

Details are provided in each individual report found in the appendices.

4 Results

Details of the following results are provided as appendices to this report.

1. Upper North Island reactive support - dynamic analysis

See Appendix 1 for the full report. The dynamic reactive support investigation identified that, following decommissioning of the last two Huntly Rankine units:

- the N-G-1 stability limit for the Upper North Island will be 2219 MW, and
- the N-1 stability limit for the Upper North Island will be 2534 MW.

This compares to the actual 2015 winter peak load of 2150 MW.

Under Transpower's Prudent load growth forecast as used for our 2015 Transmission Planning Report, and assuming the Huntly Rankine units are decommissioned at the end of 2018:

- the N-G-1 limit will first be exceeded in winter 2019[5], and
- the N-1 limit will first be exceeded in winter 2020.

Therefore, without investment in the grid, or an alternative solution, there will be a risk of load management in the Upper North Island once the last Rankine units are decommissioned.

The study also noted low voltages occurring in the Waikato region. A separate study is needed to determine whether these low voltages are an indicator of voltage stability issues in the Waikato region. This study is currently underway.

2. Upper North Island reactive support – load flow analysis

See Appendix 2 for the full report. The static voltage support investigation identified the first issue as being a risk of voltage collapse, under N-1 and N-G-1 scenarios, centred around Hamilton. The following table summarises results.

Case	Outage	UNI load limit	Forecast year (prudent)
Applying existing operating procedures	N-G-1 (Pakuranga–Whakamaru–1 and Huntly unit 5)	2075 MW	exceeded in 2015
	N-1 (Huntly unit 5)	2195 MW	2016
Altering operating procedures including increased bus voltages	N-G-1 (Pakuranga–Whakamaru–1 and Huntly unit 5)	2330 MW	2016
	N-1 (Huntly unit 5)	2555 MW	2020

With the decommissioning of Huntly generation in 2018, the transmission system will not have N-1 security if peak load coincides with an outage of Huntly unit 5.

[5] This assumes the last two Huntly Rankine units are available until the end of 2018

If operating procedures can be changed, this may be pushed out until 2020. The viability of altering operating procedures will be considered in the next stage of this project. Results from this and the dynamic investigation indicate that there will be a need for additional dynamic voltage support before static voltage support.

Transpower as System Operator has published a report, dated 3 November 2015, indicating a voltage stability limit of 2250 MW for the Upper North Island. That limit is consistent with the range found by this investigation.

3. Thermal constraints between Whakamaru and Auckland

See Appendix 3 for the full report. This investigation considered the capacity of the 220 kV transmission system between Whakamaru and Otahuhu/Pakuranga.

The following table provides a sample of the results. These assume Huntly units 1 and 2 have been decommissioned.

Generation development scenario	Outage	UNI load limit	Forecast year (prudent)
Wairakei Ring - new geothermal	N-1 (Ohinewai–Whakamaru–1)	2666 MW	2024
Wairakei Ring - new geothermal	N-G-1 (Ohinewai–Whakamaru–1 and Huntly Unit 5)	2370 MW	2016
Haywards - increased HVDC	N-1 (Ohinewai–Whakamaru–1)		Beyond 2030
Haywards - increased HVDC	N-G-1 (Ohinewai–Whakamaru–1 and Huntly Unit 5)	2608 MW	2022

In summary, following the decommissioning of Huntly units 1 and 2 the transmission system between Whakamaru and Auckland will not have N-G-1 security (it will be unable to supply peak load if it coincides with an outage of Huntly unit 5). The year that N-G-1 capacity is exceeded depends on the location of any replacement generation.

If replacement generation is located in the Wairakei Ring area, N-G-1 transmission capacity could be exceeded as soon as decommissioning occurs. If replacement generation is located in the southern North Island, South Island or Taranaki, there will be no N-G-1 constraints between Whakamaru and Auckland until at least 2022.

However, generation located in Taranaki, the southern North Island or the South Island, will create other constraints, as described in the following section.

4. Review of existing constraints south of Whakamaru

See Appendix 4 for the full report. This investigation identified transmission constraints that may occur if the decommissioned Huntly and Auckland generation is replaced by generation from other generation-rich areas. These include Taranaki and the South Island[6] (i.e. the HVDC/Wellington), Wairakei and the Bay of Plenty. The report covers only the transmission network from these regions through to Huntly and Whakamaru.

The constraints described are already known and previously described in Transpower's Transmission Planning Report. They are not changed by the generation decommissioning, but they may be more likely to bind due to the increased need for existing generation from regions south of Whakamaru or any replacement generation (constraints that bind will depend on the location of replacement generation).

The first binding constraint is the 110 kV Bunnythorpe–Mataroa–1 circuit, for generation export from the Wellington and Taranaki regions. This constraint has already been observed, particularly during some maintenance outages. There is a project underway to investigate options to resolve this, with the resulting preferred solution expected to be implemented prior to 2018. Therefore, subsequent constraints are of more interest in the medium-term.

In summary, increased generation in Taranaki and Wellington (including HVDC) is limited by the capacity of the 220 kV Tokaanu–Whakamaru circuits, followed by the Huntly–Stratford circuits. These constraints already exist so additional generation will mean they are more likely to bind.

Increased generation in the Wairakei or Bay of Plenty areas is limited by the Atiamuri–Ohakuri circuit followed by the Atiamuri–Whakamaru circuit. The 220 kV Kawerau–Ohakuri and Edgecumbe–Kawerau circuits may constrain generation export from the Bay of Plenty region. Approximately 100 MW of new generation can be added in either (but not both) of these regions before constraints are likely to occur.

There is no single area south of the Upper North Island in which replacement generation equivalent to the decommissioned generation at Huntly, Otahuhu and Southdown can be connected without creating transmission constraints during normal operation.

5. Waikato 110 kV issues

See Appendix 5 for the full report. This investigation considered the impact of the recent and proposed generation decommissioning on the Waikato 110 kV transmission network. A specific focus was the impact on our intention to permanently close the existing Arapuni 110 kV bus split in 2017, to enable the connection of a new substation in the South Waikato.

[6] The investigation only considered constraints in the North Island transmission network.

The outcome of the investigation indicates that the split should not be closed in 2017, as there will be insufficient generation to prevent circuit overloading.

This outcome will be followed by a net benefit test, industry consultation on our revised intention to retain the Arapuni bus split indefinitely and our recommended option to manage localised thermal capacity issues in the South Waikato.

6. High voltage management in the Upper North Island

See Appendix 6 for the full report. This investigation looked at the ability of the System Operator to manage voltage levels in the Upper North Island, following the recent and proposed generation decommissioning.

At times of light load, such as overnight during summer, System Operator action is usually required to prevent transmission system voltages exceeding their prescribed upper limits. In recent years this has often included removing one or two transmission circuits from service overnight.

This investigation found that the system voltages will still be manageable following the generator decommissioning. However, it is noted that there is likely to be an economic case for investment to assist in managing high voltages, and this will be investigated at the next stage.

A.1 Appendices

Appendix 1:

UNI generation decommissioning – UNI dynamic reactive support need analysis

Appendix 2:

UNI generation decommissioning – UNI reactive support need, load flow analysis

Appendix 3:

UNI Generation Decommissioning –Thermal constraints between Whakamaru and Auckland

Appendix 4:

UNI Generation Decommissioning – Transmission constraints south of Whakamaru

Appendix 5:

UNI Generation Decommissioning – Waikato 110 kV issues

Appendix 6:

UNI generation decommissioning – High Voltage Management

UNI Generation Decommissioning Report

APPENDIX 1: Upper North Island Dynamic Reactive Support - Need Analysis

March 2016

Keeping the energy flowing

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Executive summary

This report presents the findings of the investigation into the dynamic reactive need date in the upper North Island.

The results of the investigation showed that the upper North Island is at risk of dynamic voltage instability as soon as all the Huntly Rankine units are decommissioned.

The analysis found that the most onerous contingency is Pakuranga–Whakamaru–1 when Huntly unit 5 is not in service during winter (i.e. N-G-1, where Huntly unit 5 is the “G”). If all of the Huntly Rankine units are decommissioned in 2016, the upper North Island is at risk of dynamic voltage instability with prudent winter load forecast under the N-G-1 scenario.

Table 0-1 summarises the results of the dynamic voltage stability studies. The year indicated is the first year in which the voltage performance criteria is breached by at least one major bus and/or generator bus in the upper North Island.

Table 0-1: Dynamic voltage stability results

Case	Load year criteria is breached	UNI load limit (MW)[1]	Contingency
Winter N-1	2020	2534	PAK–WKM–1
Winter N-G-1	2016[2]	2219[2]	PAK–WKM–1
Summer N-1	Beyond 2035	N/A	PAK–WKM–1
Summer N-G-1	2019	1972	PAK–WKM–1

1. The load includes 5% margin.
2. This assumes the two remaining Huntly Rankine units (unit 1 and 2) are decommissioned in 2016.

Low voltages were noted in the Waikato region. A separate study is needed to determine if these low voltages flag that voltage stability issues also exist in the Waikato region.

Dynamic studies inherently have modelling uncertainties, especially the proportion and type of motor load and the dynamic behaviour of the motor and other loads. It is proposed to undertake a motor load survey to better assess the proportion and type of motor load. More detailed investigations will also be undertaken which include sensitivity studies of the technical assumptions. This will refine the need date, size and optimum location of additional dynamic support where the need for this investment is identified in this report.

1 Purpose of this document

The purpose of this report is to present the results of upper North Island dynamic reactive support needs analysis.

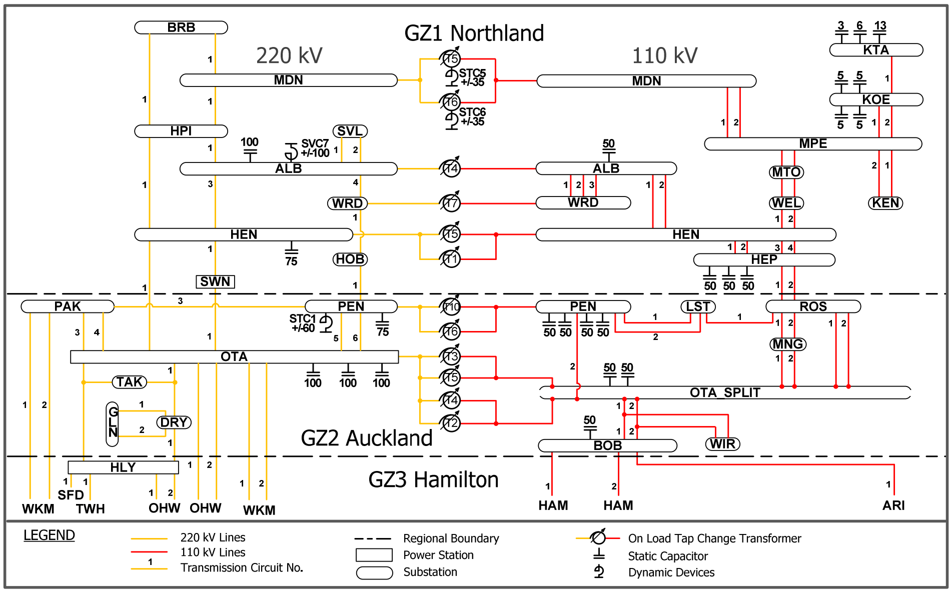
2 Introduction

2.1 Purpose of the investigation

The upper North Island region covers the geographical area north of Huntly including Bombay, Auckland, North Isthmus and Northland (see Figure 2-1). The transmission networks are shown in Figure 2-2.

Figure 2-1: Upper North Island 220 kV and 110 kV network

Figure 2-2 Upper North Island 220 kV and 110 kV schematic



The upper North Island does not have enough local generation to meet local demand, and the shortfall is met from distant generation at and south of Huntly. The situation will continue as there is no new committed generation in the upper North Island, and worsen with the recent and future decommissioning of generation totalling 1555 MW[1] in the upper North Island announced by three major electricity generators, with the last 500 MW to be decommissioned by December 2018 (unless market conditions change).

Beyond 2018, the upper North Island will also rely on distant generation to help maintain the voltage stability to within acceptable tolerances.

Shunt capacitor banks provide only static voltage support. Conventionally switched capacitors cannot provide the dynamic response required for sudden power system events when a rapid response is required to maintain voltage quality. For such events, dynamic reactive support devices such as generators, synchronous condensers, static var compensators (SVCs), and static synchronous compensators (STATCOMs) are required.

Static and dynamic reactive support in the upper North Island is currently provided by a combination of shunt capacitor banks, two STATCOMs, an SVC and the generators at Huntly (when connected). The need for investment will grow as load continues to grow in the region.

The purpose of the investigation was to determine the need date for investment in the upper North Island when 1555 MW of thermal generation retires.

2.2 Scope of the investigation

The scope of this investigation was to determine the N-1 and N-G-1 need dates and corresponding load limits due to transient voltage stability in upper North Island.

[1] The thermal generation that is or will be decommissioned in the upper North Island is:
- Southdown CCGT (175 MW, decommissioned);
- Otahuhu CCGT (380 MW, decommissioned);
- Huntly Rankine units 3 and 4 (250 MW each, decommissioned);
- Huntly Rankine units 1 and 2 (250 MW each, will be decommissioned by December 2018 unless market conditions change).

3 Findings and conclusions

The investigation found that the worst contingency is a 2ϕ to ground fault on Pakuranga–Whakamaru–1 (PAK-WKM-1) during winter when Huntly unit 5 is not in service[2] (or not offered into the electricity market).

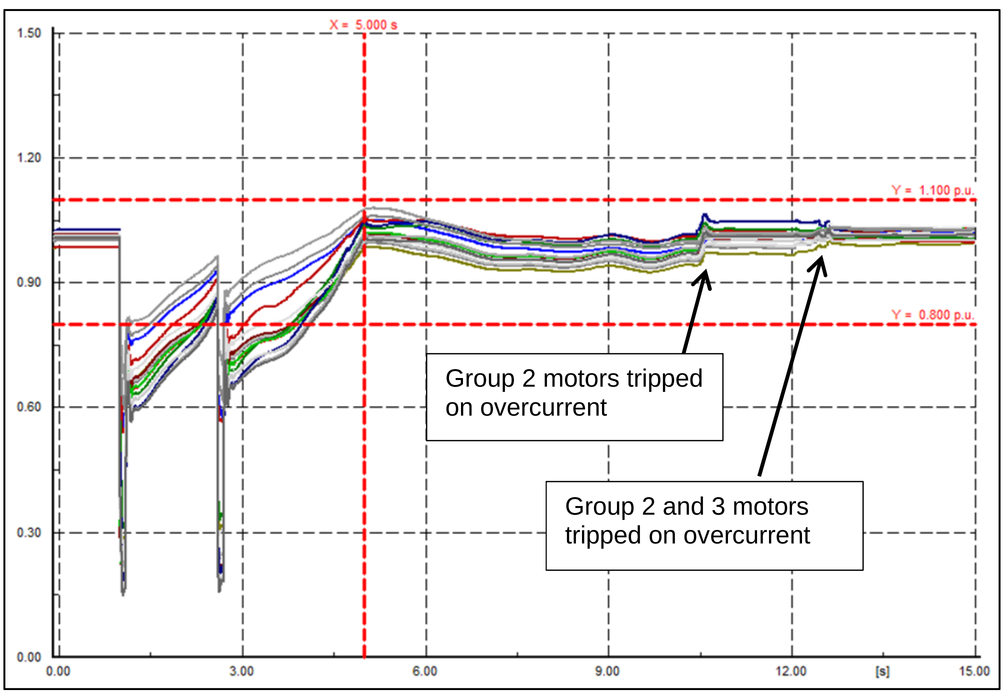
The results include standard modelling assumptions for dynamic studies. This includes a permanent 2ϕ to ground fault, applied at 1 second with the faulted circuit disconnected (tripped) after 100 milliseconds, and an autoreclose reclose onto the circuit which is still faulted 1.5 seconds after the initial fault. The results also model 25% of group one motor loads disconnecting during or shortly after the fault due to the motor control or protection. These standard modelling assumptions and others are as discussed in Appendix A. The transmission buses monitored are listed in Appendix B.

Figure 3-1 to Figure 3-6 shows the voltage recovery at major buses and/or generator buses in the upper North Island.

3.1 Winter N-1

Figure 3-1 shows the voltage recovers adequately in 2023. Group 2 motors were tripped at about 10.5 seconds and about 12.3 seconds (motor current greater than 3 pu for more than 8 seconds).

Figure 3-1: Bus voltages for a 2ϕ-G fault 100ms with auto-reclose N-1 fault at Pakuranga–Whakamaru–1 winter 2023



2 Huntly unit 5 is 400 MW and is the largest single generator in the upper North Island. If the generator is out of service for an extended period due to a generator fault, then it will have a significant impact on the transmission system.

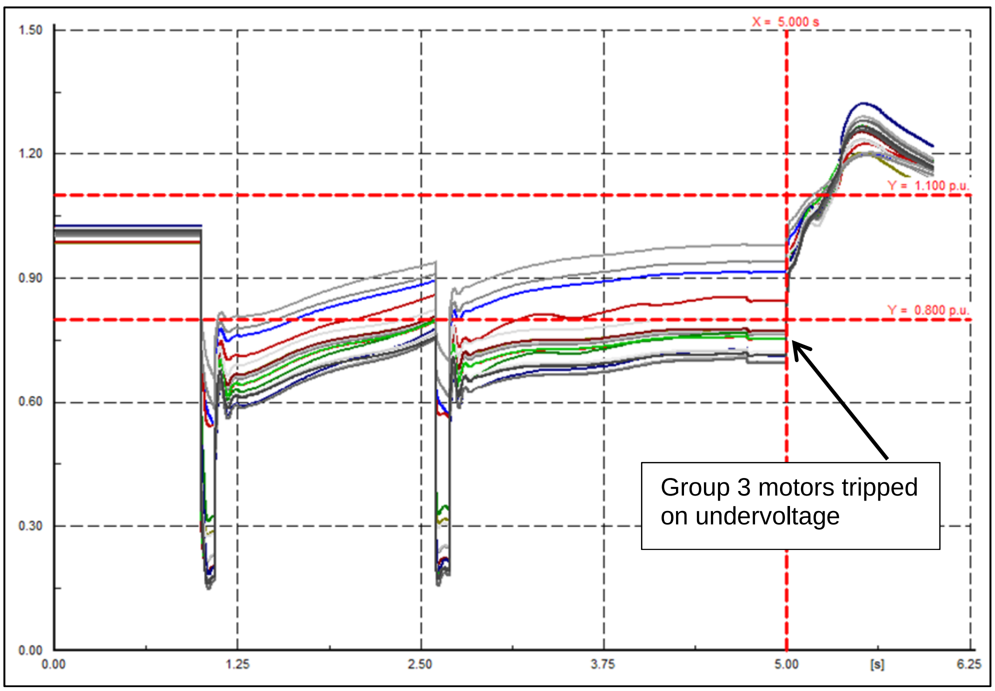
Figure 3-2 shows that the upper North Island is at risk of dynamic voltage instability from winter 2024. Compared to Figure 3-1, the incremental load growth from 2023 to 2024 means the available dynamic reactive support is insufficient in the upper North Island to provide enough voltage support, causing a slow voltage recovery.

A large number of transmission buses breach the voltage criteria (see Figure 3-2). Consequently the Group 3 motors were tripped due to undervoltage 4 seconds after the first fault. This represents the expected response of Group 3 motors to this undervoltage.

The motor tripping causes the voltage to swing in the opposite direction, causing high bus voltages greater than 1.1 pu.

Buses at Maungaturoto 110 kV and Mount Roskill 110 kV usually breach the criteria first, followed by Bream Bay 220 kV, Mangere 110 kV, and Hepburn 110 kV.

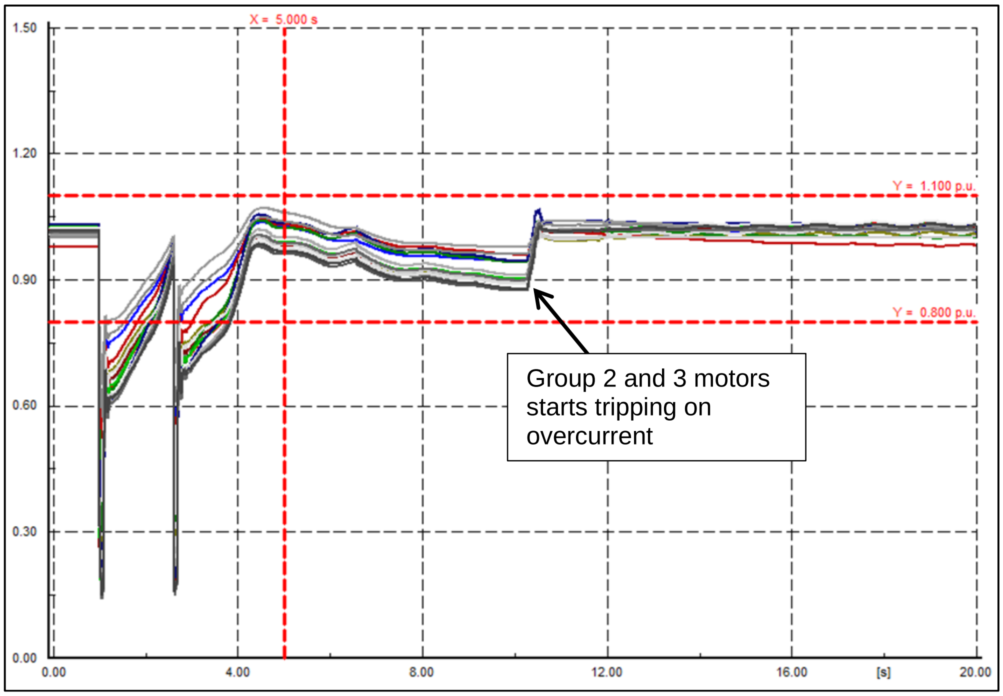
Figure 3-2: Bus voltages for a 2ϕ-G fault 100ms with auto-reclose N-1 fault at Pakuranga–Whakamaru–1 winter 2024



3.2 Winter N-G-1

Figure 3-3 shows that the upper North Island is not at risk of dynamic voltage instability if all the Huntly Rankine units are out of service, under the N-G-1 scenario, for an upper North Island winter load of 2305 MW[3]. This is more than the 2015 actual peak load of 2150 MW.

Figure 3-3: Bus voltages for a 2ϕ-G fault 100ms with auto-reclose N-G-1 fault at Pakuranga–Whakamaru–1: 2305 MW upper North Island load (assuming all Huntly Rankine units were not available)

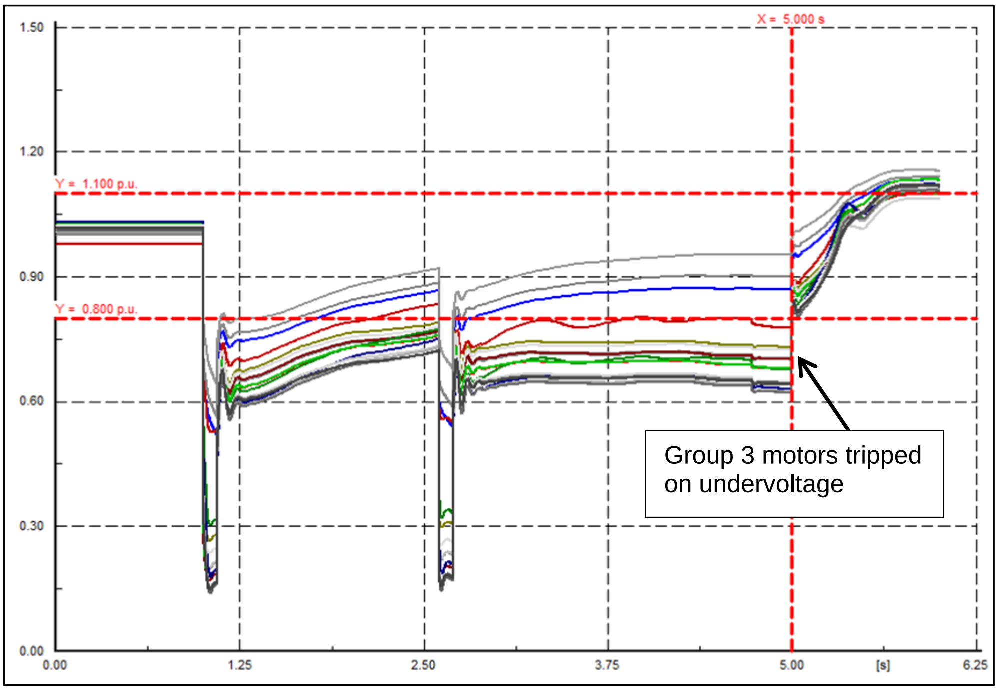


[3] 2305 MW is the winter island prudent peak forecast value. Upper North Island load will be 2190 MW when taking 5% margin into consideration.

Figure 3-4 shows that the upper North Island is at risk of dynamic voltage instability if all the Huntly Rankine units are out of service under N-G-1 scenario, for an upper North Island load of 2336 MW[4].

Comparing the results in Figure 3-3 with Figure 3-4, the difference in the upper North Island N-G-1 load limit (if all the Huntly Rankine units are out of service) is 31 MW. The difference in load between the results shown in the two figures represents about one year of load growth.

Figure 3-4: Bus voltages for a 2ϕ-G fault 100ms with auto-reclose N-G-1 fault at Pakuranga–Whakamaru–1: 2336 MW upper North Island load (assuming all Huntly Rankine units were not available)

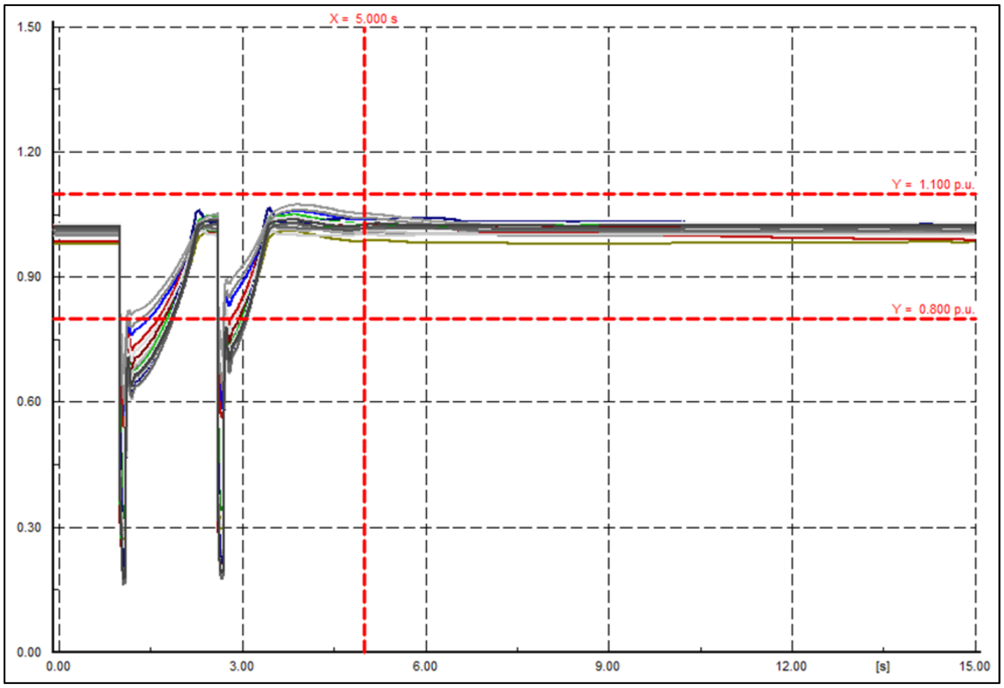


[4] 2336 MW is the winter island prudent peak forecast value. The upper North Island load is 2219 MW when taking 5% margin into consideration.

3.3 Summer N-1

Figure 3-5 shows that the upper North Island is not at risk of dynamic voltage instability with summer 2035 load under the N-1 scenario. The analysis showed that the voltage recovers adequately in summer 2035.

Figure 3-5: Bus voltages for a 2ϕ-G fault 100ms with auto-reclose N-1 fault at Pakuranga–Whakamaru–1 summer 2035



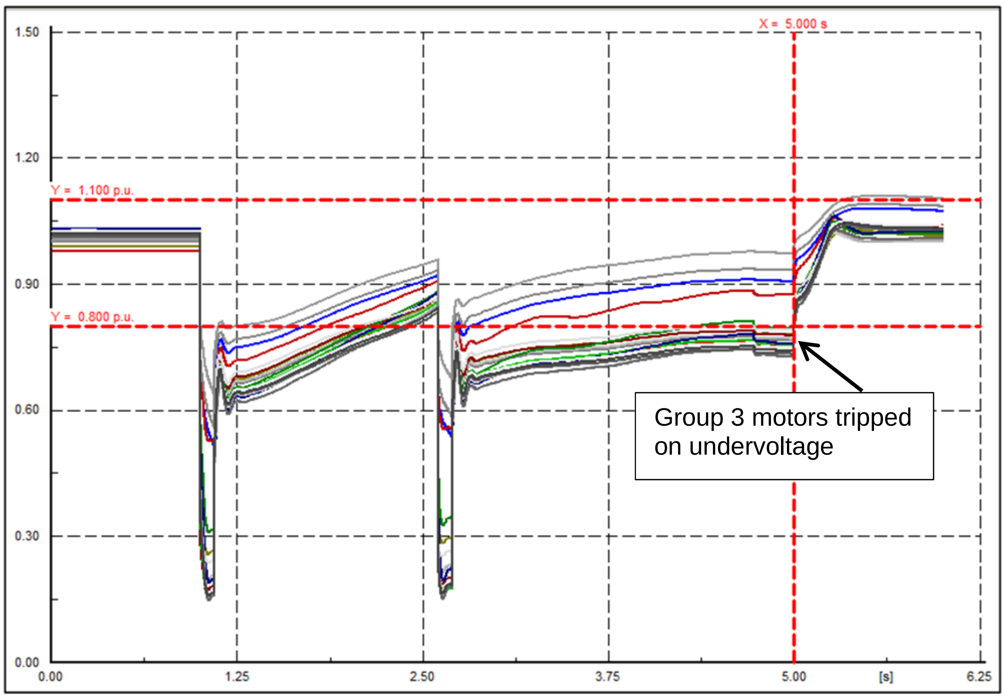
3.4 Summer N-G-1

Figure 3-6 shows that the upper North Island is at risk of dynamic voltage instability with summer 2023 load under the N-G-1 scenario.

The bus voltages did not recover adequately 4 seconds after the first fault. Consequently Group 3 motors were tripped on undervoltage.

Group 2 motors were tripped at about 10.3 seconds (motors had greater than 3 pu current for more than 8 seconds) and about 14 seconds (motors had greater than 1.1 pu for more than 0.9 seconds).

Figure 3-6: Bus voltages for a 2ϕ-G fault 100ms with auto-reclose N-G-1 fault at Pakuranga–Whakamaru–1 summer 2023



3.5 Upper North Island load limits

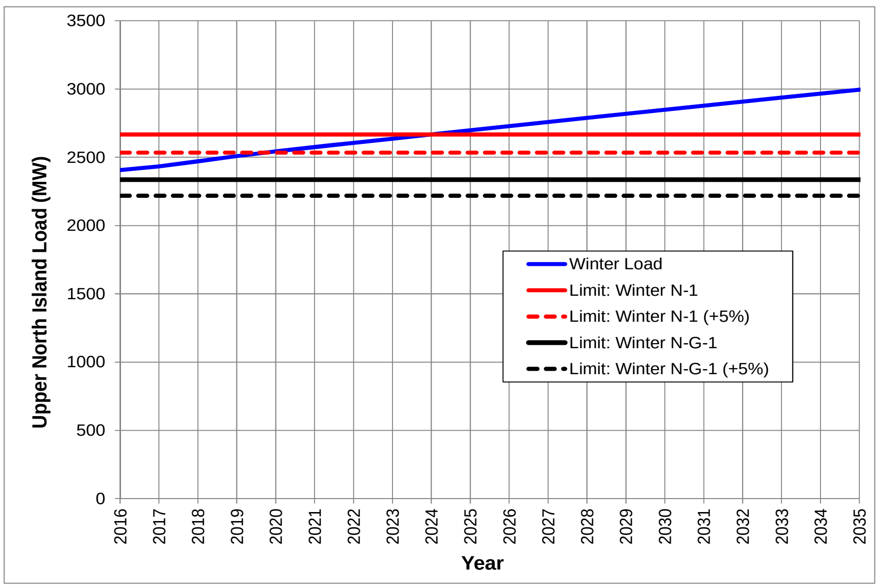
Figure 3-7 shows the load limits for dynamic voltage stability in upper North Island. The dynamic voltage stability analysis did not include a 5% margin on upper North Island load. A 5% margin brings forward the:

- N-1 (summer) need date, no issues within the planning timeframe
- N-1 (winter) need date from 2024 to 2020
- N-G-1 (summer) need date from 2023 to 2019.

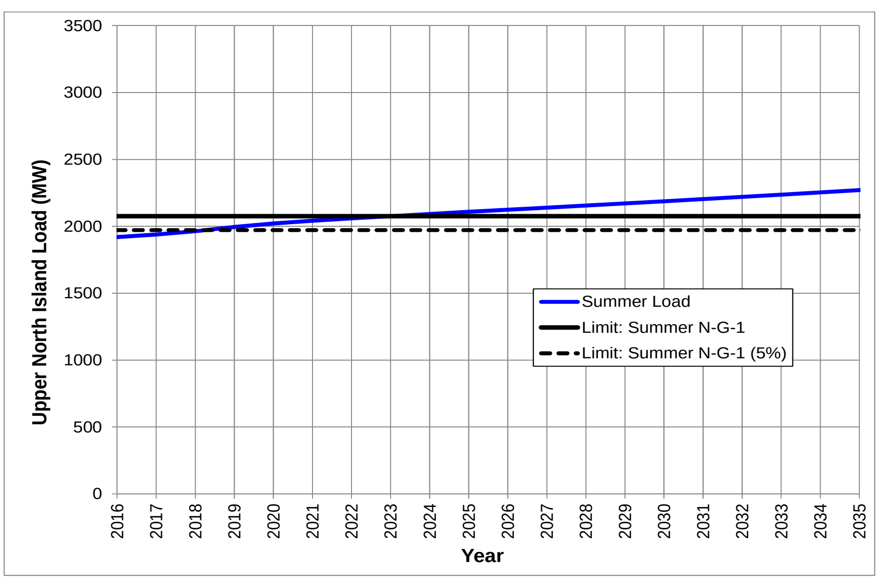
However, for the N-G-1 (winter) scenario, the upper North Island load is at risk of dynamic voltage instability as soon as the last two Huntly Rankine units are decommissioned.

Figure 3-7: Upper North Island dynamic voltage stability limits

(a) Winter limits



(b) Summer limits



3.6 Static capacitor requirement

Table 3-1 shows the amount of additional reactive power support needed in the upper North Island to maintain the transmission buses at their set points pre-contingency. Note that positive values mean that the reactive source is providing reactive power to the network, and negative values mean that the reactive source is absorbing reactive power from the network.

Table 3-1: Static capacitor requirement (pre-contingency)

Case	Load year criteria is breached	Additional pre-contingency reactive support (Mvar)			
		Albany 220 kV	Marsden 220 kV	Otahuhu 220 kV	Hamilton 220 kV
Winter N-1	2024	-5	+3	+57	+130
Winter N-G-1	2016[1]	-46	-12	+43	+104
Summer N-1	Beyond 2035	N/A	N/A	N/A	N/A
Summer N-G-1	2023	-92	-4	-114	+53

1. This assumes the two remaining Huntly Rankine units (unit 1 and 2) are decommissioned in 2016.

Table 3-1 shows that additional static reactive support is required at Otahuhu as soon as the last two Rankine units at Huntly are decommissioned to maintain the pre-event voltage setpoints.

3.7 Impact of operating decommissioned generators as synchronous condensers

The investigation found that it is possible to maintain dynamic voltage stability in the upper North Island by retaining the decommissioned generating units as synchronous condensers. To maintain dynamic voltage stability in winter 2018 would require at least:

- two Southdown generators (G101, and G102), or
- one Huntly Rankine unit.

Alternatively, retaining two Huntly Rankine units as synchronous condensers will defer the winter N-G-1 need date to 2025.

4 Recommendations

The investigation recommends a study into the:

- transient voltage recovery for the Waikato region
- sensitivity of the need date to the combination of static shunt capacitor size and placement to delay the need date for dynamic reactive plant,
- sensitivity of the need date to different voltage profile at major upper North Island buses
- sensitivity to the amount of Group 1 motors that trip to identify whether it is economic to avoid some motor load disconnecting during voltage recovery because of energy not served benefits
- sensitivity to the sequence of events such as N-1-G compared with N-G-1
- the impact of using PZQZ characteristics for static load model.

5 Analysis

5.1 Assumptions

This section describes the assumptions made in the analysis. Assumptions include the:

- demand forecast
- motor loads
- generation assumptions
- dynamic reactive plant dispatch
- steady state voltage support
- voltage profile
- transient voltage performance criteria
- methodology

5.1.1 Demand Forecast

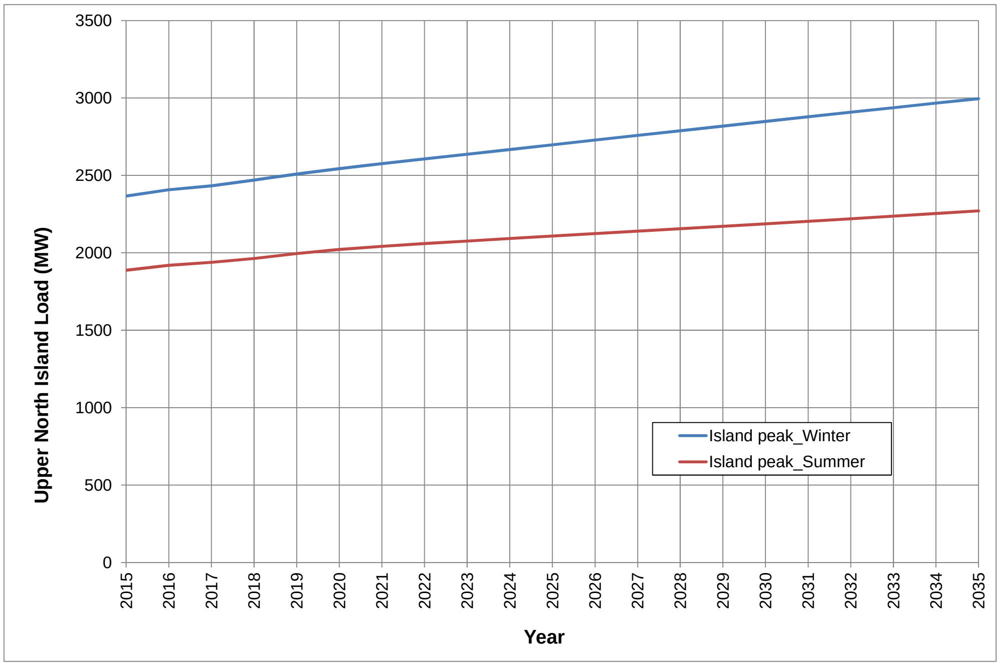
The analysis used the 2015 Transmission Planning Report North Island prudent peak demand forecast for 2015 to 2030 load year.

The upper North Island peak demand forecast is listed in Table 5-1 and plotted in Figure 5-1. The power factor values area listed in Appendix C for each grid exit point in the North Island.

Table 5-1: Upper North Island demand forecast

Year	Peak Demand (MW)	
	Winter	Summer
2015	2366	1888
2016	2406	1919
2017	2433	1938
2018	2470	1964
2019	2509	1995
2020	2544	2021
2021	2575	2041
2022	2606	2060
2023	2636	2076
2024	2667	2093
2025	2698	2109
2026	2728	2124
2027	2758	2140
2028	2788	2155
2029	2819	2171
2030	2849	2187
2031	2878	2204
2032	2908	2220
2033	2937	2236
2034	2967	2254
2035	2996	2270

Figure 5-1: Upper North Island demand forecast



5.1.2 Motor loads

The amount and type of motor load connected within the distribution networks has a significant influence on the amount of dynamic reactive support required. The assumptions used in this investigation are given in Appendix A.

5.1.3 Generation Assumptions

Table 5-2 lists the upper North Island generation dispatch.

Table 5-2: Upper North Island generation dispatch (beyond 2018)

Generation	P (MW)	Q (Mvar) (+ve capacitive range, -ve inductive range)
OTC	0	0
Southdown	0	0
Ngawha	25	0
Glenbrook	77	0
Huntly-U1	0	0
Huntly-U2	0	0
Huntly-U3	0	0
Huntly-U4	0	0
Huntly-U5	400	+202
Huntly-U6	40	+38

The total upper North Island generation is 542 MW. The N-G-1 scenario assumes the biggest generator in upper North Island (i.e. Huntly-U5) is not offered to the electricity market or on maintenance outage, which brings the total UNI generation down to 142 MW.

The analysis assumed that Huntly unit 1 and unit 2 will be retired by December 2018. Otahuhu Combined Cycle has been decommissioned, and Southdown is decommissioned.

5.1.4 Existing upper North Island reactive support

Dynamic

The existing upper North Island dynamic reactive support is listed in Table 5-3.

Table 5-3: Dynamic reactive support

UNI dynamic Reactive Support	Reactive power range (Mvar) (+ve capacitive range, -ve inductive range)
Marsden STC	+80/-68[1]
Penrose STC	+/-60[1]
Albany SVC	+/-100

1. The Penrose and Marsden STATCOMs have a 2 seconds overload of +/-80 Mvar.

Pre-contingency the STATCOMs and SVC are dispatched at 0 Mvar so that the devices maintain dynamic reserve to respond to the system events.

Static

Table 5-4 lists the capacitors that are used for voltage support in upper North Island.

Table 5-4: Static support (pre-contingency)

Capacitor	Voltage (kV)	Reactive (Mvar)	Dispatch (Mvar)
Albany C1	110	50	50
Albany C2	220	100	100
Bombay C11[1]	110	50	0
Henderson C1	220	75	0
Hepburn Road C11	110	50	50
Hepburn Road C12	110	50	50
Hepburn Road C13	110	50	50
Kaitaia C1 binary capacitor[2]	11	22.4	3.4
Otahuhu C11	110	50	50
Otahuhu C12	110	50	50
Otahuhu C29	110	100	100
Otahuhu C30	110	100	100
Otahuhu C31	110	100	100
Penrose C1	220	75	0
Penrose C11	110	50	0
Penrose C12	110	50	50
Penrose C13	110	50	50
Penrose C14	110	50	50
Wairau Road C1[1]	33	18	0
Wairau Road C2[1]	33	18	0

1. Capacitor was not dispatched in the analysis.
2. Total Kaitaia binary capacitor is 22.4 Mvar. The analysis assumed 3.4 var was available for dispatch.

5.1.5 Voltage support assumptions

In each forecast year capacitors are switched pre-contingency to maintain the pre-contingency voltage profile (see Table 5-5). Additional capacitance was modelled if the voltage profile cannot be maintained.

These voltage set points are based on average value during peak hours over the 2015 winter period. Determining if these are the optimum voltage set points following the last decommissioning of thermal generation in December 2018 will be determined as part of the next stage of the investigations.

Table 5-5: Bus voltages maintained in upper North Island for both summer and winter

Bus	Voltage (pu)
MDN220	1.000
ALB220	1.022
OTA220	1.020
HAM220	1.010
WKM220	1.026
MTI220	1.035
WPA220	1.039

5.1.6 Contingency

Table 5-6 lists the contingencies used in the investigation.

Table 5-6: N-1 and N-G-1 contingency

Type	Contingency
N-1	Pakuranga–Whakamaru–1
N-1	Huntly–Takanini–Otahuhu
N-1	Otahuhu–Whakamaru–1
N-1	Albany SVC
N-1	Hobson Street–Penrose–1
N-1	Ohinewai–Otahuhu–1
N-1	Henderson–Otahuhu–1
N-1	Hamilton–Whakamaru–1
N-1	Huntly-U5
N-G-1	Huntly-U5, Pakuranga–Whakamaru–1
N-G-1	Huntly-U5, Huntly–Takanini–Otahuhu
N-G-1	Huntly-U5, Otahuhu–Whakamaru–1
N-G-1	Huntly-U5, Albany SVC
N-G-1	Huntly-U5, Hobson Street–Penrose–1
N-G-1	Huntly-U5, Ohinewai–Otahuhu–1
N-G-1	Huntly-U5, Henderson–Otahuhu–1
N-G-1	Huntly-U5, Hamilton–Whakamaru–1

5.2 Grid planning guidelines[5]

5.2.1 Voltage recovery criteria

[5] Grid Planning Guideline 2014, Section 9.

Transpower's transient voltage criteria are derived from the fundamental requirements set out in the Electricity Industry Participation Code (EIPC) reliability standard for the New Zealand Power Transmission System.

The recovery criteria for major (220 kV and 110 kV) and generator buses are:

- Voltage must be greater than 0.5 pu following a single credible contingency event which removes an item of equipment from service without a transmission system short circuit fault. For modelling purposes, all load is assumed to stay connected during and following the event;
- Voltage must recover to above 0.8 pu in less than 4 seconds following a credible contingency event. This requirement is to ensure that voltages have recovered to the extent that under-voltage based protection relays on grid connected generating units do not operate which would cause the units to disconnect from the power system;
- Voltage overshoot must be limited to below 1.3 pu. This applies for areas that are remote from the HVDC link terminals such as the upper North Island and upper South Island. This requirement is to ensure that overvoltage based protections on generating units do not operate which would cause the generating unit to disconnect from the power system;
- Voltage overshoot must not be above 1.1 pu for more than 0.9 seconds. This requirement is based on the normal operating range for voltages in the Part 8 of EIPC;
- There is no pole slipping on grid connected generating units. This requirement is to ensure that protection relays on generating units do not operate to remove the unit from the power system.

5.2.2 Economic investments criteria

It is additionally possible to make economically justified investment in addition to the voltage criteria. The economic investment criteria is based on the amount of avoidable tripped motor load during a fault.

The overvoltage and undervoltage criteria are listed in Section 5.2.1. In addition, motor current must not be greater than 6 times the rated current (6 pu) for more than 3 seconds and not be greater than 3 times the rated current (3 pu) for more than 8 seconds.

The load models and their protection are described in Appendix A.

5.3 Methodology

In addition to the transient voltage performance criteria, the following requirements are also made when undertaking the analysis:

- Load is increased by 5% of the forecasted load, to maintain a margin between the stability limit and the predicted load level.
- 25% of the expected Group 1 contactor connected motors will trip.
- The worst expected fault type is a close-in double phase to ground fault with an unsuccessful auto-reclose attempt assuming it is not as option to disable the auto-reclose (or increase the re-close time) for any of the critical circuits.

5.4 Other generation and slack generator

- The HVDC link at Haywards provides 1200 MW to the North Island.
- No new generation planned in the upper North Island area for the study period.
- Generation development scenarios are not considered in this study.
- Wind generation contribution during the peak period is 100% of its installed capacity.
- A slack generator without dynamic response was modelled at the Whakamaru 220 kV bus.

5.5 Planning horizon

The analysis considers 20 years of demand forecast (2015 to 2035).

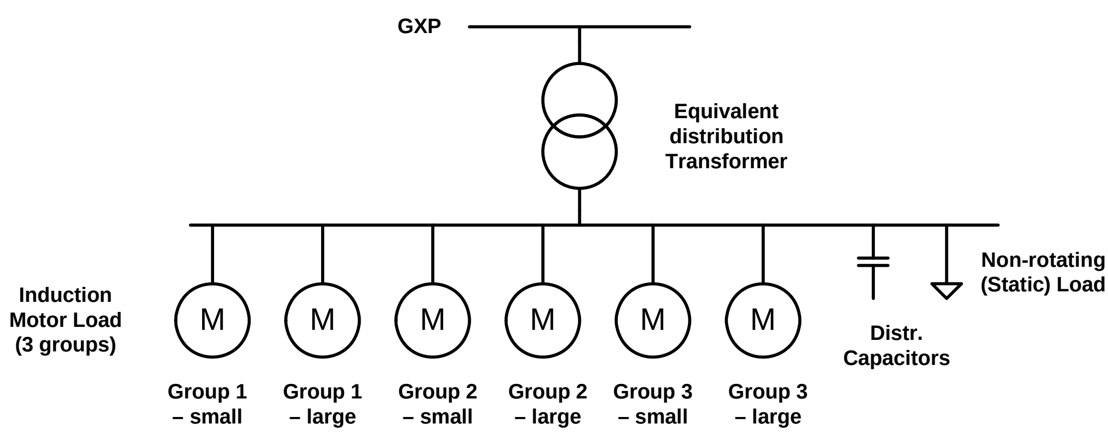
Appendix A Motor load modelling[6]

The load model determines how the load reacts to faults and dips in voltages. In the studies the load model is based on the motor load data surveyed by SKM in 2013.

The load model consists of:

- induction motor load
- static "non rotating" load
- known distribution capacitors

Figure A-1: Load model, modelled at each upper North Island grid exit point



A.1 Induction motors

The induction motors are split into three different protection groups (groups one, two and three). Each group is further subdivided into groups based on motor sizes (large and small) as shown in Figure A-1.

Note that other motor types, such as DC motors, and synchronous motors have been not found to be present in large numbers. Due to their comparative rarity their effect will be minimal and are not included in the studies.

A.1.1 Group 1 motor

Group 1 motors are connected with electromagnetic contactors. These contactors may open and stay open when the motors are subjected to low voltage conditions. This is modelled by assuming that some of group one upper North Island motor loads will trip during a nearby under voltage fault. In the power system simulations the amount of group one motors that trip is assumed to be 25%. The remaining 75% of group one motor is split to group two and three motor with proportional ratio.

The Group 2 and Group 3 motor loads are assumed to either remain connected, or reconnect shortly after the fault.

A.1.2 Group 2 and 3 motor

Both Group 2 and Group 3 motors have overvoltage and overcurrent protection but only Group 3 motor has undervoltage protection (see Table A-1).

6 Geoff Love, *Upper North Island Dynamic Reactive Support: Technical assessment of options, May 2010.*

Table A-1: Motor protection[7]

Protection	Group 1	Group 2	Group 3
Electromagnetic	Yes	No	No
Over-current	Yes	Yes	Yes
Over-voltage	Yes	Yes	Yes
Undervoltage	Some	No	Yes

A.2 Static load

The static load is assumed to stay connected during the fault. It is modelled as having the following voltage dependent characteristics;

- real power, P, has a constant current characteristic
- reactive power, Q, has a constant impedance characteristic

This characteristic is commonly called PIQZ.

A.3 Distribution capacitor banks

Distribution capacitor banks are needed to support voltage in the distribution network and meet distribution companies' power factor obligations. Known distribution capacitors are explicitly modelled.

A.4 Distribution network

The distribution network is modelled as a transformer between the grid exit point and the load. A network impedance of 10% is assumed (where the load MW demand is the MVA base).

A.5 Load model composition

The composition of each grid exit point is that found by SKM in their 2013 motor load survey. The load composition was surveyed in the peak winter period and the extreme summer period. The load composition for the entire upper North Island is summarised in Table A-2.

Table A-2: Upper North Island Load Composition Summary

Period	Static	Induction motors					
		Group One		Group Two		Group Three	
		Large	Small	Large	Small	Large	Small
Winter GXP average	50%	6.3%	18.3%	1.4%	13.4%	2.8%	7.8%
Extreme Summer GXP average	59.7%	5.7%	14.5%	1.2%	11.8%	2.2%	5.6%

7 Victor Lo, *Upper North Island Grid Upgrade Investigation Project: Need Analysis (NP532), February 2013.*

Appendix B Monitored transmission bus

Bus	Voltage (kV)
BOB110	110
BRB220	220
GLN_G3	11
GLN_M1	11
GLN220	220
GLN33_3	33
HEP110	110
HLY_UN2	16.5
HLY_UN4	16.5
HLY_UN5	18
HLY_UN6	11
HOB110	110
KTA110	110
LST110	110
MNG110	110
MTO110	110
NWA11	11
NWA33	33
ROS110	110
SWN220	220
WIR110	110

Appendix C Forecast power factor

Northland	At island peak winter prudent	At island peak summer prudent
Bream Bay	0.972	0.968
Kensington	1	0.992
Marsden	1	1
Maungatapere	0.977	0.969
Maungaturoto	1	0.998
Wellsford	1	1
Auckland		
Albany (Wairau Road)	0.998	0.998
Albany 33 kV	0.994	0.985
Bombay 110 kV	0.994	0.978
Bombay 33 kV	0.987	0.957
Glenbrook 33 kV-1	1	1
Glenbrook 33 kV-2	0.976	0.953
Glenbrook-NZ Steel	1	0.991
Henderson	0.997	0.997
Hepburn Road	0.997	0.973
Hobson Street	0.989	0.97
Meremere	0.976	0.978
Mangere 110 kV	0.884	0.876
Mangere 33 kV	0.988	0.974
Otahuhu	0.995	0.997
Pakuranga	0.991	0.981
Penrose 22 kV	0.978	0.956
Penrose 33 kV	0.986	0.975
Penrose 110 kV - LST	0.997	0.973
Mount Roskill 22 kV	0.983	0.976
Mount Roskill - KING	0.998	0.956
Silverdale	0.998	0.999
Southdown	1	1
Takanini	0.997	0.998
Wiri	0.993	0.984
Waikato		
Cambridge	0.989	0.964
Hamilton 11 kV	0.996	0.982
Hamilton 33 kV	0.995	0.984
Hamilton NZR	1	1
Hinuera	0.98	0.944
Huntly	1	1
Hangatiki	0.928	0.89

Kinleith 11 kV (T1, T2, T3)	0.848	0.845
Kinleith 11 kV (T5)	-0.888	-0.907
Kinleith 33 kV	0.993	0.97
Kopu	1	1
Lichfield	0.954	0.949
Maraetai	1	1
Piako	0.988	0.958
Putaruru	1	1
Te Awamutu	0.99	0.96
Te Kowhai	0.995	0.988
Waihou	1	0.995
Whakamaru	1	1
Waikino	0.999	0.999
Bay of Plenty		
Edgecumbe	0.971	0.944
Kawerau 11 kV (T1, T2)	0.888	0.864
Kawerau 11 kV (T11, T14)	1	1
Kawerau 11 kV (T6, T7, T8, T9)	0.983	0.988
Kaitimako	1	1
Matahina	1	1
Mt Maunganui 11 kV	1	0.95
Mt Maunganui 33 kV	0.991	0.979
Owhata	0.995	0.986
Rotorua 11 kV	0.997	0.99
Rotorua 33 kV	0.989	0.963
Tauranga 11 kV	0.996	0.979
Tauranga 33 kV	0.979	0.989
Te Kaha	0.984	0.944
Te Matai	0.98	0.964
Tarukenga	1	0.995
Waiotahi	0.989	0.967
Central North Island		
Bunnythorpe 33 kV	0.983	0.963
Bunnythorpe NZR	1	1
Dannevirke	0.99	0.953
Linton	0.993	0.979
Mangamaire	0.991	0.957
Mangahao	0.959	0.943
Marton	0.975	0.932
Mataroa	0.987	0.977
National Park	0.979	1
Ohaaki	0.994	0.955
Ohakune	0.983	0.98

Ongarue	1	0.981
Tokaanu	0.997	0.95
Tangiwai 11 kV	1	0.999
Tangiwai NZR	1	1
Woodville	1	0.999
Waipawa	0.972	0.921
Hawke's Bay		
Fernhill	0.983	0.949
Gisborne	0.984	0.955
Gisborne	0.986	0.964
Redclyffe	0.989	0.971
Tokomaru Bay	0.984	0.955
Tuai	0.995	0.988
Whirinaki	1	1
Wairoa	0.985	0.948
Wairoa	1	1
Whakatu	0.984	0.965
Whirinaki	1	1
Taranaki		
Brunswick	0.974	0.928
Carrington St	0.98	0.951
Huirangi	0.964	0.919
Hawera	0.983	0.956
Hawera (KUPE)	-0.968	-0.963
Motunui	0.936	0.918
Moturoa	0.99	0.971
Opunake	0.937	0.903
Stratford 220 kV	1	1
Stratford 33 kV	0.985	0.934
Taumarunui	1	1
Wanganui	0.939	0.938
Waverley	0.957	0.905
Wellington		
Central Park 11 kV	0.992	0.973
Central Park 33 kV	0.988	0.977
Gracefield	0.99	0.974
Greytown	0.995	0.954
Haywards 11 kV	0.997	0.991
Haywards 33 kV	0.987	0.984
Kaiwharawhara	0.992	0.978
Melling 11 kV	0.99	0.97
Melling 33 kV	0.996	0.997

Masterton	0.982	0.956
Pauatahanui	0.99	0.994
Paraparaumu	0.995	0.99
Takapu Rd	0.995	0.995
Upper Hutt	0.998	0.998
Wilton	0.998	0.99

UNI Generation Decommissioning Report

APPENDIX 2: Upper North Island Reactive Support need – load flow analysis

March 2016

Keeping the energy flowing

TRANSPOWER

Transpower New Zealand Limited The National Grid

Table of contents

Executive summary

The upper North Island (UNI) reactive support load flow study forms part of the overall UNI generation decommissioning investigation.

The purpose of this investigation was to determine, taking into consideration the planned generation decommissioning in the UNI:

1. the voltage stability load limit in the UNI, and

2. the amount of additional static reactive support required in the UNI to support the existing dynamic reactive equipment.

Conservative simplifying assumptions were used. Where a need for transmission investment is identified, this is the earliest probable need date. More detailed investigations are required to refine the need date and optimise the size and location of additional reactive support[1].

The load limits for the UNI were determined for the following system conditions:

- N (all transmission elements and generators in service).
- N-1 (one transmission contingent event, e.g. circuit, reactive source, generator (N-G)).
- N-G-1 (one transmission contingent event and one generator out of service).

Upper North Island load limit with Huntly units 1 and 2 available

With two Huntly Rankine units in service, the N-1 voltage stability limit for the upper North Island is more than 2700 MW. Based on our current prudent load forecast, the UNI load will not exceed this limit until beyond 2025.

Upper North Island load limit with Huntly units 1 and 2 decommissioned

The UNI voltage stability limit is driven by voltage collapse in the Waikato/Central North Island region. One of the weak buses identified is Hamilton 220 kV.

The voltage stability limit depends on a number of assumptions. Two sets of results are given here, for two sets of assumptions:

1. Voltage set points at major buses in the UNI are maintained as presently operated, meaning that not all existing capacitors are switched into service, and

2. Voltage setpoints at UNI busses increased, allowing all existing capacitors to be switched into service.

To find transmission limits into the UNI, new generation is added at Whakamaru when the load exceeds available generation.

Table 0-1 and Table 0-2 below summarise the results.

[1] The conservative simplifying assumptions include maintaining the voltage levels at key UNI sites at their historic values and operating the existing dynamic reactive support at either zero (to provide maximum dynamic headroom for post-contingency support) or absorbing reactive power pre-contingency. Determining if different voltage levels are more appropriate and/or if less dynamic headroom is acceptable would be done as part of a detailed study, if the need for transmission investment is confirmed.

Table 0-1 UNI voltage stability limits

UNI voltage set points	Contingency type	Contingency	UNI voltage stability limit
As presently operated:	N-1	Pakuranga–Whakamaru–1 or 2	2330 MW
	N-G	Huntly unit 5	2195 MW
	N-G-1	Pakuranga–Whakamaru–1 or 2 and Huntly unit 5	2075 MW
Set points raised to get all capacitors into service:	N-1	Pakuranga–Whakamaru–1 or 2	2595 MW
	N-G	Huntly unit 5	2555 MW
	N-G-1	Pakuranga–Whakamaru–1 or 2 and Huntly unit 5	2330 MW

Explanation of voltage set points and generation assumptions

In the early years of the study period, not all of the existing static capacitors are required pre-contingency (N or N-G system conditions). With the historical voltage set points in the upper North Island, up to seven capacitors need to be off to maintain dynamic reserves at Albany (i.e. to keep the Albany SVC output near zero).

This is how the system is presently operated. This is appropriate for historical load peaks.

As peak loads increase, raising the voltage set point at the Albany 220 kV bus to 1.05 pu will allow additional capacitors to be switched in while still maintaining dynamic reserves at Albany.

To supply the higher load limits reported in Table 0-1, all existing generation must be in service and some additional generation added. Therefore, practically the N-G limit of 2555 MW cannot be supplied by the existing power system. 2555 MW can be described as the theoretical limit, achievable under ideal conditions. Less-than-ideal generation dispatch patterns, outages of transmission components and challenges with operating at the limit mean that the UNI voltage stability limit usually falls between approximately 2200 MW and 2500 MW. The actual value is assessed and set in real time based on generation and grid conditions at the time.

We anticipate that it will be impractical to operate the transmission system above about 2400 MW in the UNI without further investment in dynamic voltage support and/or generation. Additional dynamic support will be required before additional static support.

Upper North Island voltage control (static reactive support)

As peak load increases, additional static reactive support (capacitors) is required so that dynamic devices can continue to operate at near zero output pre-contingency. Table 0-2 below indicates the amount of additional reactive support required.

Table 0-2: Static reactive support requirement

Bus	Voltage set point (pu)	Static reactive support requirement
Albany 220 kV	1.05	Indicative need date: 2022 if Huntly unit 5 is out of service Installing one 50 Mvar capacitor at Albany in 2023 is sufficient to maintain dynamic reserve up to 2030 and beyond.
Marsden 220 kV	1.025	Indicative need date: 2025 Installing one 10 Mvar capacitor at Marsden in 2025 is sufficient to maintain dynamic reserve until beyond 2030 with and without Huntly unit 5 generating.
Otahuhu 220 kV	1.045	Indicative need date: 2021 if Huntly unit 5 is generating Installing one 100 Mvar capacitor at Otahuhu in 2021 and a 100 Mvar capacitor every four years will maintain dynamic reserve if Huntly unit 5 is generating. Indicative need date: 2019 if Huntly unit 5 is out of service Installing two 100 Mvar capacitors at Otahuhu in 2019 and a 100 Mvar capacitor every 2 to 3 years will maintain dynamic reserve if Huntly unit 5 is out of service.

The additional reactive support is modelled at the Albany, Marsden and Otahuhu 220 kV buses. Refining the need date and determining the optimum size and location of any additional reactive support will be part of a separate investigation.

1 Purpose of this document

The Upper North Island (UNI) reactive support load flow study forms part of the UNI thermal generation decommissioning investigation.

The purpose of this investigation is to determine the UNI load limit, need date and the amount of additional dynamic and static reactive support needed in the UNI under the following system conditions, taking into consideration generation decommissioning:

- N (all transmission elements and generators in service)
- N-1 (one transmission contingent event, e.g. circuit, reactive source, generator (N-G))
- N-G-1 (one transmission contingent event and one generator out of service).

2 Introduction

2.1 Background

Following a series of announcements regarding closures of thermal plants in the upper North Island (UNI) region, Transpower has embarked on a number of studies to understand the impact on the transmission grid and constraints that are forecast to arise.

2.2 The transmission network

The Upper North Island (UNI) is everything at and north of Huntly, including Bombay and Glenbrook. Supply security to this region is influenced by:

- generation in Auckland and Huntly.
- static and dynamic reactive support in the UNI area.
- transmission network supplying the UNI area, including the transmission network south of Auckland.
- load composition (more relevant to dynamic voltage stability).

The existing transmission network is shown geographically in Figure 2-1 and schematically in Figure 2-2.

The UNI region is primarily supplied by eight 220 kV circuits from the south of Auckland, and three 110 kV lower capacity circuits from Arapuni (with two circuits via Hamilton). The eight 220 kV transmission circuits are:

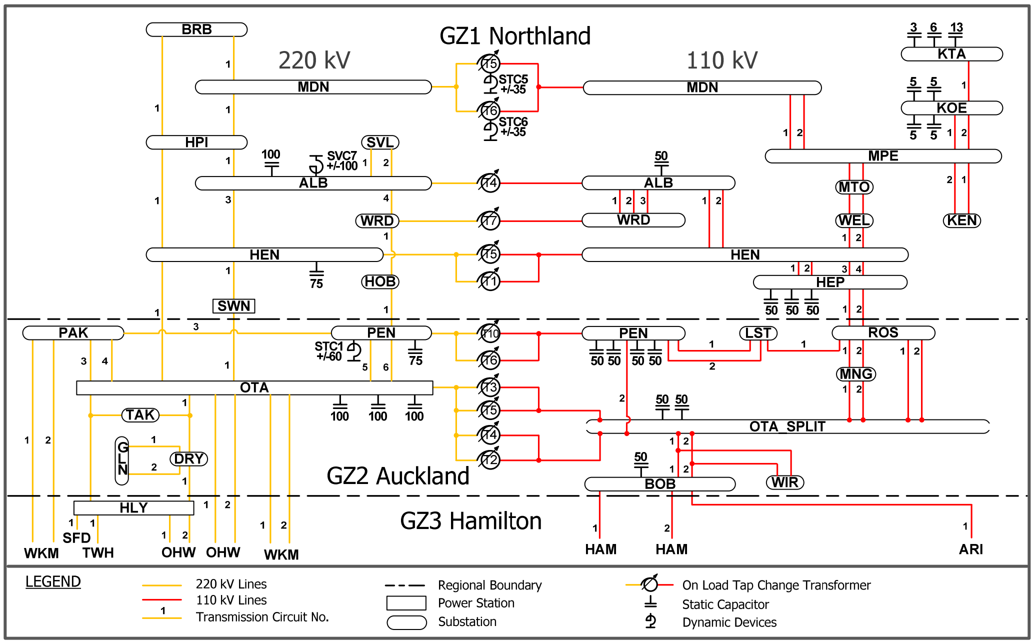
- two Huntly–Otahuhu circuits, with one circuit via Drury
- two Ohinewai–Otahuhu circuits
- two Otahuhu–Whakamaru circuits, and
- two Pakuranga–Whakamaru circuits.

The reactive power support in the region is provided by:

- STATCOMs at Marsden and Penrose
- Static var compensator (SVC) at Albany
- 220 kV capacitors at Albany, Henderson, Otahuhu and Penrose
- 110 kV capacitors at Albany, Hepburn Road, Bombay, Otahuhu and Penrose, and
- 33 kV and 11 kV capacitors at Kaitaia and Kaikohe.

Figure 2-1: UNI region transmission system

Figure 2-2: Single line schematic for UNI



2.3 Scope of the investigation

The scope of this report is limited to steady state analysis of the upper North Island (UNI) region. This includes the:

- UNI load limit taking into consideration the planned generation decommissioning, and
- need date and the reactive power requirements to maintain key UNI buses at set voltage levels while allowing existing UNI dynamic devices to operate at near zero reactive power output pre-contingency.

Out of scope:

This investigation does not consider:

- the planned replacement of some of the capacitors in the UNI region (separate studies will be carried out to find the need for these capacitors and the impact of decommissioning them)
- Circuit thermal overload issues, or
- Optimal locations for new capacitors.

3 Analysis

3.1 Upper North Island load limit (PV analysis)

3.1.1 Methodology

The dynamic reactive plant (SVC and STATCOM) in the UNI is used to provide the fast dynamic response required for sudden power system events to maintain voltage quality. They are normally operated at zero output pre-contingency to allow them to have the greatest dynamic reserve to respond to transient events. In order to maintain the dynamic reserves, not all static capacitors will necessarily be in service under certain operating conditions.

To determine the effect of operating conditions on the UNI load limit:

- The existing capacitors are progressively switched off to assess the impact on the dynamic sources if the historical voltage set points are maintained.
- The UNI load limit is found by steadily increasing the UNI load until the load flow fails to converge following a contingent event.
- The work is repeated with higher voltage set points to test the results.

The actual winter 2015 load of 2150 MW is used as the base for this study.

3.1.2 Results

Existing limits

With two Huntly Rankine units in service, there are no issues supplying UNI load under an N-1 security level until beyond 2025. The N-1 voltage stability load limit for the upper North Island is more than 2700 MW.

Post-2018 limits with historic voltage set points

With two Huntly Rankine units decommissioned, the first binding constraint is due to voltage collapse in the Waikato/Central North Island region. One of the weak buses identified is Hamilton 220 kV. The load limits presented in this section refer to the load attained (with 5% load margin) before the load flow fails to converge.

Sensitivity to capacitor switching

Table 3-1 shows the progression of capacitor switching and the impact on the dynamic sources. The results show that seven capacitors must be switched off to maintain UNI dynamic reserve[2] and historical voltage set points.

Table 3-1: Pre-contingency capacitor switching impact on dynamic reactive support (negative means absorbing reactive power)

Capacitor switched OFF	Albany SVC	Marsden STATCOM	Penrose STATCOM
Albany C2	-102	-73	-35
+ Albany C1	-101	-58	-29
+ Hepburn Road C11	-101	-42	-23

[2] The shunt capacitors in the UNI were designed to manage circuit outages prior to completion of the NIGU and NAaN projects. This is why there appears to be an excess of capacitors in the region under the scenario described here.

Capacitor switched OFF	Albany SVC	Marsden STATCOM	Penrose STATCOM
+ Hepburn Road C12	-100	-26	-17
+ Otahuhu C29	-87	-6	-6
+ Hepburn Road C13	-48	-2	-4
+ Penrose C11	-13	0	-2

With this capacitor configuration the load flow no longer converges, for a Huntly unit 5 contingent event when the upper North Island reaches 2305 MW[3]. Taking a 5% voltage stability margin the upper North Island load limit is 2195 MW. Table 3-2 shows the UNI load limits with other contingent events.

Table 3-2: UNI load limit with historical operating voltage set points

Contingency	UNI load limit
N-G (Huntly unit 5)	2195 MW
N-1 (Pakuranga–Whakamaru–1 or 2)	2330 MW
N-G-1 (Huntly unit 5 and Pakuranga–Whakamaru–1 or 2)	2075 MW

Post-2018 limits with increased voltage set points

As peak loads increase, raising the voltage set points at Albany 220 kV to 1.05 pu and Marsden 220 kV to 1.025 pu will allow additional capacitors to be switched in while still maintaining the UNI dynamic reserves.

This section presents the impact of capacitor switching and voltage set points on the upper North Island voltage stability limits, post decommissioning of the remaining two Huntly Rankine units.

Table 3-3 summarises the increase in load limit achieved by raising the voltage set points. The results show that to maintain an N-1 voltage stability margin in winter 2019, the voltage set point at Albany 220 kV bus must be raised to 1.05 pu. The 2019 winter peak prudent forecast for UNI is 2517 MW.

Table 3-3: Voltage set point changes to increase voltage stability limit

Capacitor switched ON	UNI load limit (MW)	Albany 220 kV bus voltage (pu)	Marsden 220 kV bus voltage (pu)
None	2195	1.022	1.005
+ Penrose C11	2240	1.024	1.005
+ Hepburn Road C13	2280	1.027	1.008
+ Otahuhu C29	2355	1.034	1.015
+ Hepburn Road C12	2395	1.036	1.016
+ Hepburn Road C11	2440	1.040	1.020
+ Albany C1	2480	1.043	1.022
+ Albany C2	2555	1.050	1.025

With voltage set points increased and all capacitors switched into service, the load flow no longer converges for a Huntly unit 5 contingent event when the upper North Island reaches 2685 MW. With a 5% voltage stability margin the upper North Island load limit is 2555 MW. Table 3-4 shows the UNI load limits with other contingent events.

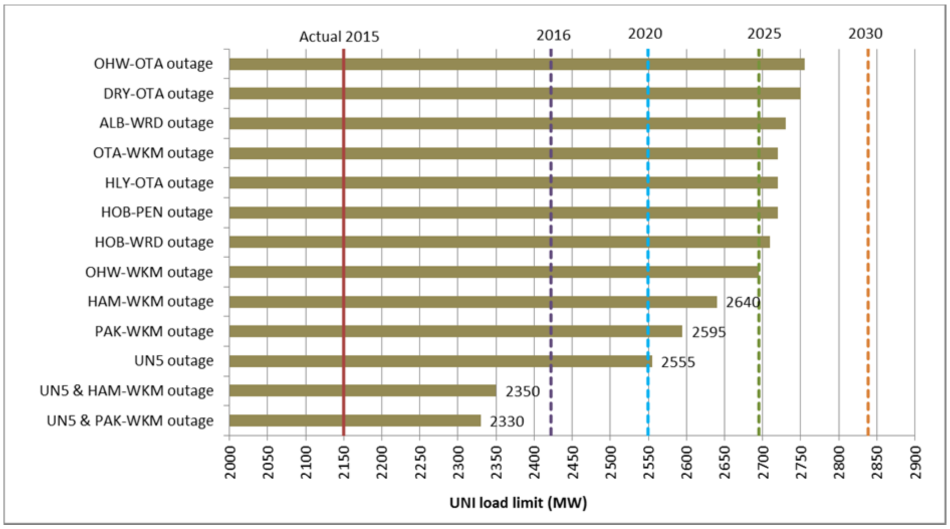
3 At this load level the dynamic plant is operated close to zero output pre-contingency, so no additional capacitors are switched in.

Table 3-4: UNI load limit with increased operating voltage set points

Contingency	UNI load limit
N-G (Huntly unit 5)	2555 MW
N-1 (Pakuranga–Whakamaru–1 or 2)	2595 MW
N-G-1 (Huntly unit 5 and Pakuranga–Whakamaru–1 or 2)	2330 MW

Figure 3-1 shows the UNI load limit with higher voltage setpoints. The load limits are plotted along with the winter prudent demand forecast for 2016, 2020, 2025 and 2030, and the actual 2015 winter load demand. The load limit includes a 5% margin below the load flow non-convergence point.

Figure 3-1: UNI load limit



Practical considerations

There are two practical considerations when estimating the voltage stability limit in the UNI:

1. To supply the UNI voltage stability load limit of 2555 MW, all existing North Island generation would need to be near full output plus significant support from the HVDC at Haywards. This is unrealistic.
2. The system will become difficult to manage in real time as the margin between allowed upper voltage limits and the voltage setpoints required for stability become squeezed.

The need for additional generation and/or dynamic voltage support is expected to precede the need for additional static voltage support.

3.2 Static reactive support need for Upper North Island dynamic reserves

This section presents the need date for additional reactive support in the UNI to allow dynamic devices to operate near zero output pre-contingency (i.e. N or N-G system conditions) whilst maintaining pre-contingency voltage set points at some key UNI buses.

3.2.1 Methodology

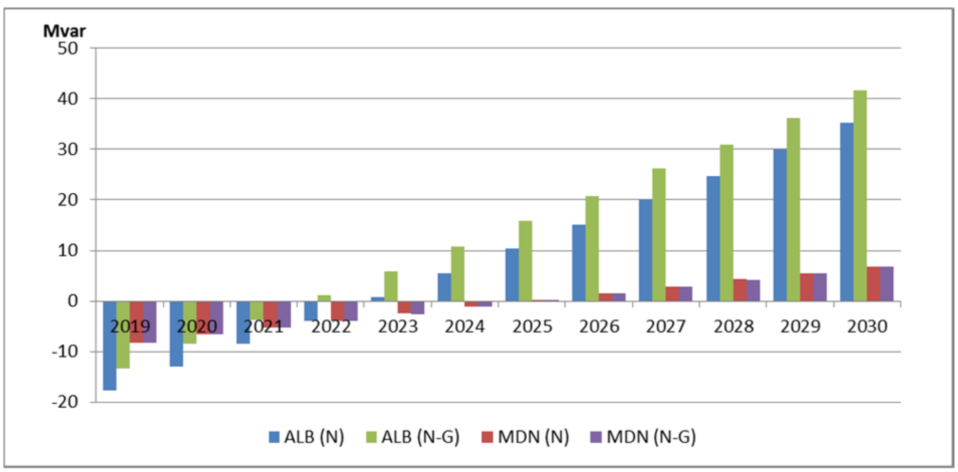
The voltage profile in the UNI area is raised higher than historical set points at three UNI nodes to maintain dynamic reserves (see Table 4-6 for details). The nodes chosen are Otahuhu 220 kV, Albany 220 kV and Marsden 220 kV as representative of the buses in the Auckland, North Isthmus and Northland areas within the UNI.

All capacitors in the UNI are switched ON. The dynamic reactive sources at Albany, Marsden and Penrose are switched OFF and represented by three infinite reactive sources modelled at the 220 kV buses at Otahuhu, Albany and Marsden to manage the voltage to their set points. When the modelled reactive power sources absorb reactive power in the early years, this shows all reactive support in the UNI is not required under certain operating conditions and capacitors may need to be switched out. When the modelled reactive power sources generate reactive power in the later years, this indicates the earliest need date when additional static capacitors are required.

3.2.2 Results

Figure 3-2 and Figure 3-3 show the additional static reactive requirement at Albany, Marsden and Otahuhu to maintain the 220 kV bus voltages at their set points. The positive axis means the reactive source is providing reactive support to the network.

Figure 3-2: Static capacitors requirement at Albany and Marsden



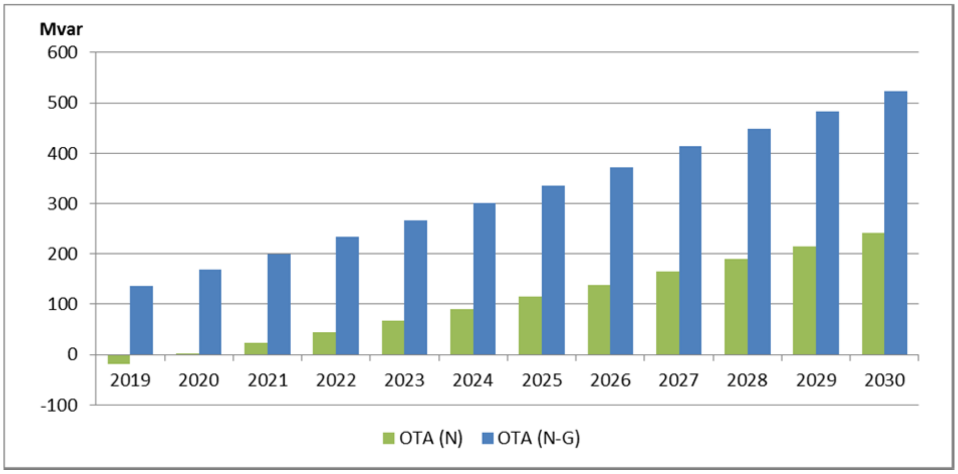
At Albany (refer to Figure 3-2):

- additional reactive support is required to maintain 220 kV bus at 1.05 pu pre-contingency in 2023 with Huntly unit 5 generating.
- installing one 50 Mvar capacitor at Albany in 2022 is sufficient to maintain dynamic reserve beyond 2030 if Huntly unit 5 is out of service.

At Marsden (refer to Figure 3-2):

- additional static reactive support is required from about 2025 to maintain Marsden 220 kV bus at 1.025 pu under N and N-G (pre-contingency).
- installing one 10 Mvar capacitor at Marsden is sufficient to maintain dynamic reserve until beyond 2030.

Figure 3-3: Static capacitors requirement at Otahuhu



At Otahuhu (refer to Figure 3-3):

- additional static capacitors are required at Otahuhu from 2021 to hold the 220 kV voltage at 1.045 pu pre-contingency. Installing one 100 Mvar capacitor in 2021 and another 100 Mvars every 4 years will maintain dynamic reserve if Huntly unit 5 is generating.
- If Huntly unit 5 is out of service during peak load period, additional static reactive support is required from 2019 to hold Otahuhu 220 kV bus at 1.045 pu pre-contingency. Installing two 100 Mvar capacitors at Otahuhu in 2019 and one 100 Mvar capacitor every 2 to 3 years will maintain dynamic reserve if Huntly unit 5 is out of service.

A separate investigation will be carried out to determine the appropriate operating voltage set points, capacitor size and location for optimum power system operations.

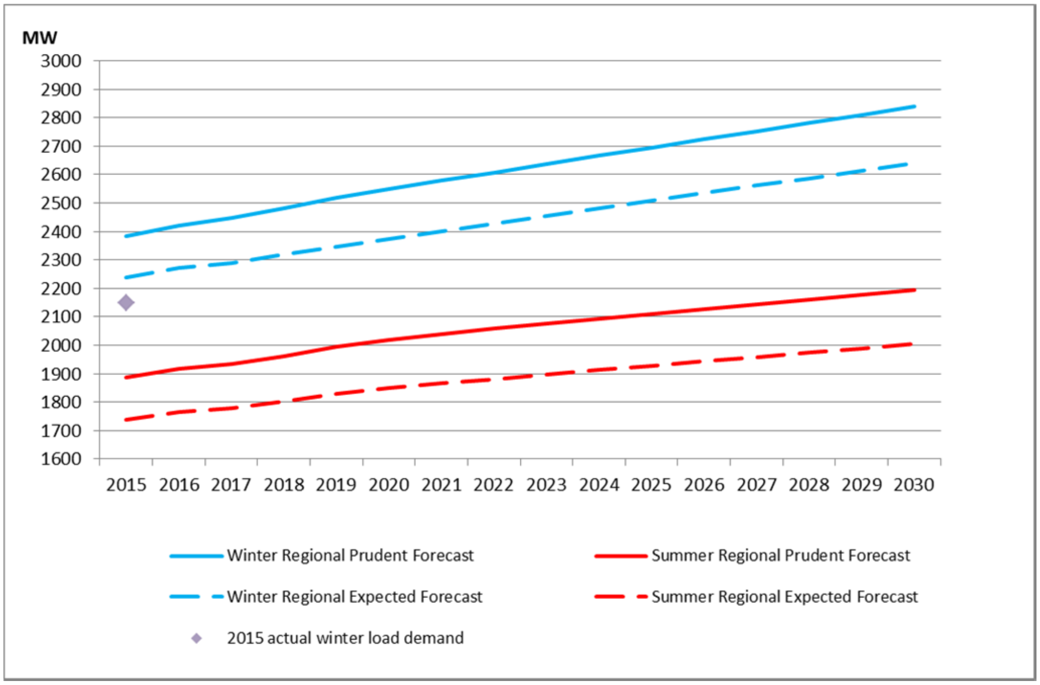
4 Assumptions

4.1 Load forecast

The load and power factor used for the study are taken from the forecast used for the 2015 Transmission Planning Report. Figure 4-1 shows the demand forecast for the UNI region. The studies described in this report used the regional winter prudent demand forecast, unless otherwise stated. The average power factor for the UNI load is 0.993 for winter peak and 0.986 for summer peak.

The actual 2015 UNI region winter load demand was 2150 MW, which is about 235 MW lower than the 2015 winter prudent load forecast.

Figure 4-1: Demand forecast (taken from 2015 Transmission Planning Report)



4.2 Generation assumptions

The generation in the upper North Island is listed in Table 4-1.

Table 4-1: UNI generation

UNI Generation	Capacity	Dispatch (MW)	Comments
Otahuhu CCGT	380 MW	0 MW	Decommission from 30 Sep 2015
Southdown	175 MW	0 MW	Decommission from 1 Jan 2016
Glenbrook	112 MW	77 MW	In service
Ngawha	25 MW	25 MW	In service
Huntly Coal (Rankine units 3 and 4) Coal (Rankine units 1 and 2) CCGT (unit 5) GT (unit 6)	 500 MW 500 MW 400 MW 50 MW	 0 MW 500 MW 400 MW 40 MW	 Decommissioned Nov 2014 and Jun 2015 Decommission from Dec 2018 In service In service

UNI Generation	Capacity	Dispatch (MW)	Comments
Te Uku	64 MW	12.8 MW	In service
Te Rapa	44 MW	40 MW	In service

Other generation and slack generator

- Wind generation contribution during peak period is 20% of its installed capacity, unless otherwise stated.
- No new generation is committed to be built in the UNI area for the study period.
- Generation development scenarios are not considered in this study.
- The HVDC link at Haywards is the first slack generator providing up to 1200 MW, -420 Mvar. An additional slack generator is modelled at Whakamaru 220 kV providing only MW to make up any generation shortfall in excess of the 1200 MW for the HVDC link.

4.3 Voltage support assumptions

Table 4-2 and Table 4-3 list the dynamic and static reactive support available in the UNI region.

Table 4-2: Dynamic reactive support

UNI dynamic reactive support	Continuous capacity (+ve capacitive range, -ve inductive range)	Pre-contingency dispatch
Albany SVC	+100/-100 Mvar	+/- 15 Mvar
Penrose STATCOM	+60/-60 Mvar	+/- 5 Mvar
Marsden STATCOM	+80/-68 Mvar	+/- 10 Mvar

Table 4-3: Static reactive support

UNI capacitor	Voltage (kV)	Reactive (Mvar)	Dispatch (Mvar)
Albany C1 C2	110 220	50 100	50 100
Bombay C11	110	50	0
Henderson C1	220	75	75
Hepburn Road C11, C12, C13	110	3 x 50	150
Kaikohe C1, C2, C3, C4	11	20	0
Kaitaia C1 binary cap	33	24	3.4
Otahuhu C29, C30, C31 C11 , C12	220 110	3 x 100 2 x 50	300 100
Penrose C1 C11, C12, C13, C14	220 110	75 4 x 50	75 200
Wairau Road C1, C2	33	2 x 18	0
Total Static Support		**1180**	

There are a number of capacitors in the UNI planned for replacement within the next 10 years (see Table 4-4). These capacitors are assumed to be replaced with like-for-like in this analysis. Separate studies will be carried out to find the need for these capacitors and the impact of decommissioning them.

Table 4-4: Planned capacitor retirement/replacement date (IWP report on 30 Sep 2015)

UNI capacitor	Voltage (kV)	Reactive (Mvar)	Scheduled retirement/replacement date
Albany C1	110	50	2017-2018
Henderson C1	220	75	2021-2022
Otahuhu C11, C12	110	2 x 50	2020-2022
Penrose C1	220	75	2022-2023

4.4 On-load tap changers

All 220/110 kV interconnecting transformers in the UNI region have on-load tap changers except Otahuhu T2. For this analysis, the auto-voltage regulation mode is switched to manual for all interconnectors north of Whakamaru, and the transformer tap position is locked as shown in Table 4-5.

Table 4-5: 220/110 kV interconnecting transformers

Interconnecting transformer	HV tap changer position
Albany T4	5
Henderson T1	5
Henderson T5	5
Otahuhu T2	1
Otahuhu T3	6
Otahuhu T4	5
Otahuhu T5	6
Penrose T6	9
Penrose T10	5
Marsden T5	9
Marsden T6	10
Hamilton T6	9
Hamilton T9	9

4.5 Upper North Island voltage profile

All static capacitors are switched ON. The bus voltages are managed by existing dynamic sources (specific for Section 3.1) or modelled infinite reactive sources placed at Albany, Marsden and Otahuhu 220 kV buses (specific for Section 0) to manage bus voltage pre-contingency as shown in Table 4-6. The generation bus voltages at relevant 220 kV generation buses and historical average operating value during peak hours over the 2015 winter period are also shown in Table 4-6.

Table 4-6: Voltage set points

Bus	Voltage (pu)	Historical average voltage (pu)
Otahuhu 220 kV	1.045	1.020
Albany 220 kV	1.050	1.022
Marsden220 kV	1.025	1.005
Huntly 220 kV	1.020	1.020
Whakamaru 220 kV	1.026	1.026

Bus	Voltage (pu)	Historical average voltage (pu)
Maraetai 220 kV	1.035	1.035
Waipapa 220 kV	1.039	1.039

4.6 Assumptions specific to the load limit calculation (Section 3.1)

Some assumptions were specific to the load limit calculation in Section 3.1[4]:

- Waikato River generation was raised from a total of 732 MW to installed capacity of 1055 MW. This change was to reduce the output of the Whakamaru slack generator using actual system generation.
- Load outside of the UNI region was reduced as shown in Table 4-7**Error! Reference source not found.** This change was to reduce the output of the Whakamaru slack bus and the impact of loads outside the upper North Island on the stability limits.

Table 4-7: Changes to loads outside the upper North Island

Grid Zone	Section 3.1 Assumption (MW)	Section 0 Assumption (MW)
Grid Zone 3 – Hamilton	567	653
Grid Zone 4 – Edgecumbe	420	569
Grid Zone 5 – Hawkes Bay	260	326
Grid Zone 6 – Taranaki	193	232
Grid Zone 7 – Bunnythorpe	260	289
Grid Zone 8 – Wellington	666	783

4.7 Transmission development

The transmission network assumed is the existing network at October 2015 plus committed transmission upgrade projects listed in Table 4-8. It included the planned UNI generation retirement as per Table 4-1.

Table 4-8: Projects relevant to UNI static reactive study

Type	Development	Study timing	Detail
Committed	Hangatiki–Te Awamutu	Winter 2017	A 110 kV circuit from Hangatiki to Te Awamutu
Existing	Arapuni bus split		Arapuni 110 kV bus remains open

Although there are a few projects planned for the UNI region (listed below) within the next 15 years, none of these projects are committed, therefore they are not considered in the analysis.

- 4 x 100 Mvar static reactive support
- Installing series capacitors on the Brownhill–Whakamaru 220 kV circuits
- Interconnecting transformer replacement (Albany T4, Henderson T1/T5, Penrose T10, Otahuhu T2)

4 The slack bus represents the additional generation required to make up the difference between the load plus losses and the generation dispatched from existing generators. The size of the slack bus influences the amount of static reactive support forecast to be required in the UNI. To reduce the influence of the slack bus in the modelling, its output was reduced by setting the Waikato generation to maximum installed capacity and reducing the load south of Whakamaru.

The 110 kV Otahuhu–Penrose–2 circuit is presently operated in the normally open position. This analysis assumed that the Otahuhu–Penrose–2 circuit is closed[5].

4.8 Steady state grid planning criteria

The analysis assumed:

- voltage at all:
  - 220 kV and 110 kV buses is maintained between 0.9 pu and 1.1 pu for both normal operating condition, and for a contingent event, and
  - 33 kV buses are maintained between 0.95 pu and 1.05 pu for both normal operating condition, and for a contingent event.
- Voltage stability of the power system maintained (i.e. the load flow solves) with an additional 5% of demand above the forecast level to allow for modelling inaccuracies.

4.9 Contingencies considered

The following contingencies were considered to determine UNI load limit.

- 220 kV Pakuranga–Whakamaru–1 or 2 circuit
- 220 kV Hamilton–Whakamaru–1 circuit
- 220 kV Ohinewai–Whakamaru–1 circuit
- 220 kV Otahuhu–Whakamaru–1 or 2 circuit
- 220 kV Ohinewai–Otahuhu–1 or 2 circuit
- 220 kV Huntly–Takanini–Otahuhu–1 circuit
- 220 kV Drury–Otahuhu–1 circuit
- 220 kV Hobson St–Penrose–1 circuit
- 220 kV Albany–Wairau Road–1 circuit
- Huntly unit 5

Following the decommissioning of Otahuhu CCGT unit, the size of Huntly unit 5 has a significant impact on UNI supply security and can influence the UNI load limit. The most onerous N-G-1 scenario is the loss of one of the Pakuranga–Whakamaru circuits when Huntly unit 5 is out of service. This scenario determines the UNI load limit.

4.10 Methodology

This analysis is based on load flow calculations using DIgSILENT Power Factory Version 15.1.4. The power system model used for the analysis is Transpower's North Island base case v5.1 developed for the 2015 Transmission Planning Report (TPR) studies.

PV analysis is conducted to find the UNI load limit. The winter 2019 load year is used as the base for this study. The UNI load limit is found by steadily increasing the UNI load until the load flow fails to converge.

The second part of the study is to find the need for additional static reactive support to allow dynamic devices to operate near zero output pre-contingency whilst maintaining pre-contingency voltage set points at some key UNI buses. In this analysis, all capacitors are switched ON. The reactive sources at Albany, Marsden and Penrose are switched OFF and replaced by three infinite reactive sources at 220 kV buses at Albany, Marsden and Otahuhu to manage the voltage to their set points. Power flow results are calculated for

[5] Operating the Otahuhu–Penrose–2 circuit normally open has relatively minor impact on the UNI load limit. The sensitivity study concluded that pre-contingency voltage set point at Albany needs to be raised by 0.002 pu to allow dynamic reserve. Two worst contingent events are the loss of Huntly unit 5 and one of the 220 kV Pakuranga–Whakamaru circuits. No change in load limit for these two contingencies.

winter 2019-2030. The need date for additional static reactive support is when these reactive sources start to produce reactive power.

UNI Generation Decommissioning Report

APPENDIX 3: Thermal constraints between Whakamaru and Auckland

March 2016

Keeping the energy flowing

TRANSPOWER

Transpower New Zealand Limited The National Grid

Table of contents

Executive summary

This report presents the results of an investigation into the thermal capacity of Transpower's 220 kV transmission system between Whakamaru and Auckland.

Purpose

The purpose of the investigation was to review the thermal capacity of transmission into Auckland in light of the decommissioning of several large thermal generators at Huntly, Otahuhu and Southdown.

Scope

The report covers thermal constraints on the 220 kV transmission lines between Whakamaru and Auckland. It only considers the case where generation at Otahuhu, Southdown and Huntly Rankine units 1 to 4 have been decommissioned. An intermediate case where two (or one) Huntly Rankine units remain in service is not considered.

The scope does not include the rest of the North Island transmission system or the 110 KV system. These are covered in other reports.

The scope does not include voltage constraints as again, these are covered in other reports.

Findings and conclusions

The results of this investigation showed some consistent themes with regard to constraints on Upper North Island circuits, but the timing of these constraints depends on the location of any new generation development.

The decommissioned generation will need to be replaced by new generation, and this may (theoretically) appear anywhere in the country. Some replacement generation is required in 2019 (when the remaining Rankine units are decommissioned) to manage the security of supply risk. Additional generation will be required a few years later to meet load growth.

Table 0-1 and Table 0-2 show the most highly loaded circuits under N-1 and N-G-1 conditions respectively. This equates to an outage of one circuit (N-1), or one circuit plus the largest single generator (N-G-1), at peak load time. The largest single generator in the Upper North Island is Huntly Unit 5.

Both tables show winter loads and ratings, as winter was the worst case season.

Table 0-1: Constraints into Auckland under N-1 up to 2030

Generation development scenario	Upper North Island load (year load is forecast)	Highly loaded circuit	Loading	Contingency causing the overload
Wairakei Ring - new geothermal	2666 MW (2024)	Hamilton-Whakamaru-1	100%	Ohinewai-Whakamaru-1
Haywards - increased HVDC	2839 MW (2030)	Otahuhu-Whakamaru-1 and 2	96%	Hamilton-Whakamaru-1
Taranaki - gas peaking	2839 MW (2030)	Otahuhu-Whakamaru-1 and 2	92%	Hamilton-Whakamaru-1

Table 0-2: constraints into Auckland under N-G-1 up to 2030

Generation development scenario	Upper North Island load (year load is forecast)	Highly loaded circuit	Loading	Contingency causing the overload
Wairakei Ring - new geothermal	2385 MW (2015)	Hamilton-Whakamaru-1	102%	Ohinewai-Whakamaru-1
	2447 MW (2017)	Otahuhu-Whakamaru-1 and 2	102%	Hamilton-Whakamaru-1
	2447 MW (2017)	Ohinewai-Whakamaru-1	101%	Hamilton-Whakamaru-1
Haywards - increased HVDC	2608 MW (2022)	Hamilton-Whakamaru-1	101%	Ohinewai-Whakamaru-1
	2637 MW (2023)	Otahuhu-Whakamaru-1 and 2	100%	Hamilton-Whakamaru-1
	2753 MW (2027)	Ohinewai-Whakamaru-1	102%	Hamilton-Whakamaru-1
Taranaki - gas peaking[1]	2839 MW (2030)	Otahuhu-Whakamaru-1 and 2	94%	Hamilton-Whakamaru-1
	2839 MW (2030)	Hamilton-Whakamaru-1	92%	Ohinewai-Whakamaru-1

1. The Taranaki results assume the Stratford-Huntly and Bunnythorpe-Whakamaru circuits are duplexed to enable the additional generation export from Taranaki.

Table 0-2 indicates that with the largest remaining Upper North Island generator out of service (Huntly Unit 5), the N-G-1 capacity of the transmission system between Whakamaru and Auckland will depend on the location of new generation development. Note that the studies assumed that all Huntly Rankine units are decommissioned and replacement generation is built.

Under all of the above scenarios there are overloaded circuits in other parts of the North Island. For example under the Taranaki generation scenario, the 220 kV Stratford-Huntly and Bunnythorpe-Whakamaru circuits are heavily overloaded.

In general, the Hamilton-Whakamaru-1 and Otahuhu-Whakamaru-1 and 2 circuits are the first to constrain power flow into Auckland.

There will be no new constraints on the 110 kV network between Arapuni and Otahuhu that are attributable to the decommissioning of generation in the upper North Island. There is an existing project to investigate investment options to secure supply to Wiri/Bombay in the long term. Future generation developments are expected to have minimal effects on the need for this investment as it is largely driven by load growth.

The conclusion from these results is that unless reliable new generation is committed in the Auckland region, some transmission or non-transmission investment will be required in the near to medium term. Due to development timeframes for transmission circuits being up to ten years, an investigation into options should be started in the near future.

1 Purpose of this document

The purpose of this report is to present results from the investigation into thermal transmission constraints between Whakamaru and Auckland, which result from the decommissioning of generation at Otahuhu, Southdown and Huntly.

2 Background

The recent and committed decommissioning of generation in the Auckland region (Otahuhu and Southdown) means that virtually all Auckland load will be supplied by the 220 kV circuits from Whakamaru and Huntly, with a small amount via the 110 kV circuits from Arapuni. Furthermore, decommissioning of all remaining coal-fired generation at Huntly (Rankine units 1 and 2), which Genesis Energy has stated will occur in December 2018 (unless market conditions change) will increase loading on some circuits into Auckland.

This is a slightly more extreme scenario than previously investigated by Transpower's Planning group. Previously it has been assumed that at least one 250 MW Rankine unit will remain at Huntly as well as the 400 MW Unit 5.

Previous studies have identified thermal constraints into Auckland as follows (from Transpower's Transmission Planning Report section 6.3.1):

> *'If the majority of new generation appears in, or injects into, the Wairakei ring area, then the 220 kV Otahuhu–Whakamaru–1 and 2 circuits may overload from 2029. These overloads can be managed operationally for the forecast period and beyond by increasing generation in the upper North Island'*

The purpose of this investigation was to determine the constraints on the transmission system north of Whakamaru in light of the announced generation decommissioning.

The diagram below shows the 220 kV circuits that were considered as part of this investigation.

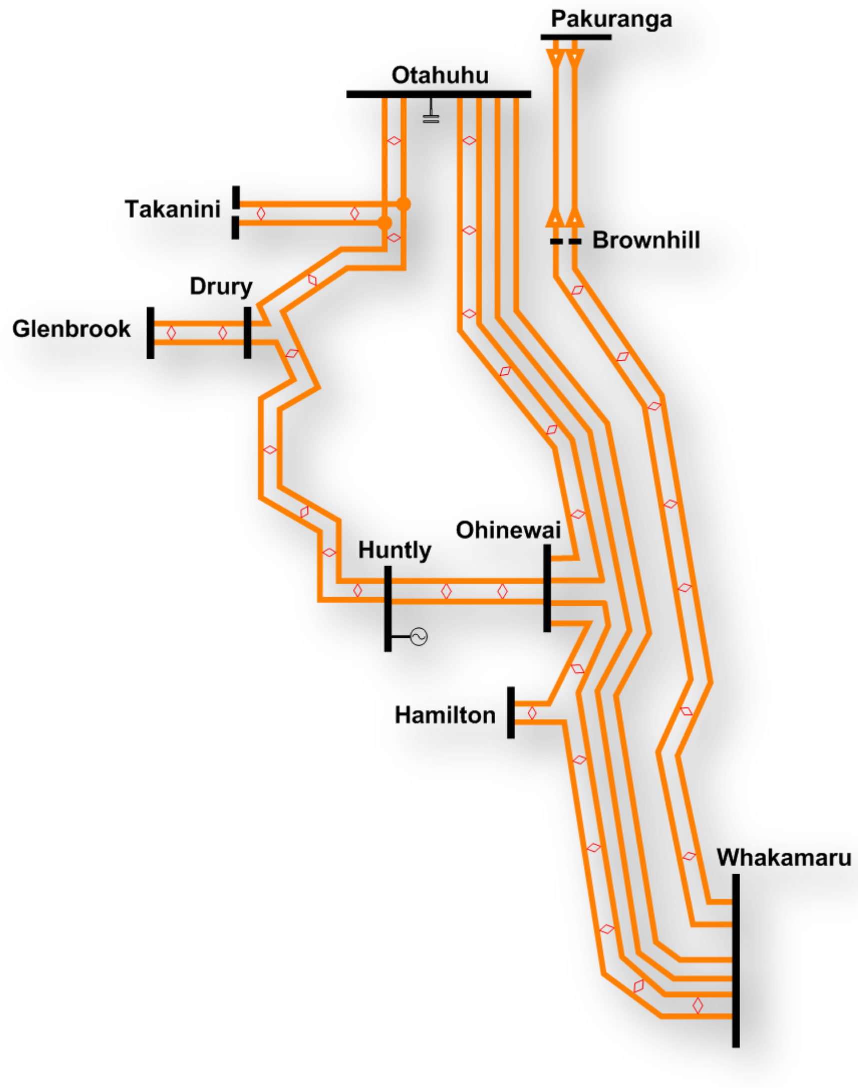


Figure 2-1: 220 kV circuits between Whakamaru and Auckland

2.1 Existing system

Table 2-1 lists details of each 220 kV circuit between Whakamaru and Auckland.

Table 2-1: 220 kV circuits between Whakamaru and Auckland

Line	Circuit	Conductor	Conductor Rating Summer	Conductor Rating Winter
Brown Hill-Whakamaru North A	BHL-WKM-1	Triplex sulfur AAAC	1354 MVA	1490 MVA
	BHL-WKM-2	Triplex sulfur AAAC	1354 MVA	1490 MVA
Brown Hill-Pakuranga A	BHL-PAK-1	2500mm^2 XLPE cable	633 MVA	676 MVA
Brown Hill-Pakuranga B	BHL-PAK-2	2500mm^2 XLPE cable	633 MVA	676 MVA

Line	Circuit	Conductor	Conductor Rating Summer	Winter
Huntly-Otahuhu A	HLY-TAT-2	Duplex zebra GZ 75°C	694 MVA	764 MVA
	DRY-HLY-1	Duplex zebra GZ 75°C	694 MVA	764 MVA
	DRY-TAT-1	Duplex chukar AC 75°C	1140 MVA	1254 MVA
	OTA-TAT-1	Duplex chukar AC 75°C	1140 MVA	1254 MVA
	OTA-TAT-2	Duplex chukar AC 75°C	1140 MVA	1254 MVA
Huntly Deviation A	HLY-OHW-1	Duplex zebra GZ 75°C	694 MVA	764 MVA
	HLY-OHW-1	Duplex zebra GZ 75°C	694 MVA	764 MVA
Otahuhu-Whakamaru C	OHW-WKM-1	Duplex goat GZ 80°C	615 MVA	671 MVA
	HAM-WKM-1	Duplex goat GZ 80°C	615 MVA	671 MVA
	HAM-OHW-1	Duplex goat GZ 80°C	615 MVA	671 MVA
	OHW-OTA-1	Duplex goat GZ 80°C	615 MVA	671 MVA
	OHW-OTA-2	Duplex goat GZ 80°C	615 MVA	671 MVA
Otahuhu-Whakamaru A	OTA-WKM-1[1]	Simplex goat GZ 75°C	293 MVA	323 MVA
Otahuhu-Whakamaru B	OTA-WKM-2[1]	Simplex goat GZ 75°C	293 MVA	323 MVA

1. Variable Line Rating is in effect on these circuits – see Section 5.3 Variable line ratings

3 Scope

Included in this investigation:

This investigation examined potential thermal constraints on the 220 kV circuits into Auckland under N-1 and N-G-1 scenarios. It considered winter and summer ratings and prudent load growth forecasts.

It only considers the case where all Southdown, Otahuhu and Huntly Units 1-4 are decommissioned.

Excluded from this investigation:

Voltage constraints.

Thermal constraints on circuits south of Whakamaru or north of Otahuhu.

The case where one or two Rankine units remain operational at Huntly.

4 Assumptions

4.1 System configuration

The Arapuni 110 kV bus remains split, with four units supplying Kinleith, and four on the North bus.

The 110 kV Bunnythorpe-Mataroa 1 circuit is split to avoid overloading the 110 kV circuit between Bunnythorpe and Arapuni.

The Penrose reactor R862 is in service (the bypass breaker is open) to balance loading between the 220 kV Henderson-Otahuhu circuits and the NAaN cable.

4.2 Voltage set points

For this study, voltage set points were as given in Table 4-1.

Table 4-1: Voltage set points

Bus	Voltage (p.u)
Marsden220 kV	1.000
Albany 220 kV	1.022
Otahuhu 220 kV	1.020
Huntly 220 kV	1.020
Whakamaru220 kV	1.026
Maraetai 220 kV	1.047
Waipapa 220 kV	1.049
Arapuni 110 kV	1.028
Karapiro 110 kV	1.030
Stratford 220 kV	1.030

Additional voltage support was added where required to ensure the model converged. These are set out in the Results section (Section 6) for each case.

4.3 Demand forecast

The demand forecast used was Transpower's 2015 Transmission Planning Report regional peak forecast.

The Upper North Island region includes Northland and Auckland as far south as Glenbrook and Bombay. This equates to GZ 1 + GZ 2. The forecast used for this region in the investigation is given in Table 4-2 below.

Table 4-2: Regional peak forecast (MW) for the Upper North Island

Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2030
Winter peak	2422	2447	2481	2517	2550	2579	2608	2637	2666	2695	2839
Summer peak	1917	1935	1962	1994	2020	2040	2059	2077	2094	2112	2196

4.4 Generation

All existing North Island generation is set at or close to its maximum.

The HVDC is injecting 1200 MW at Haywards under all scenarios, and more in addition to this under the HVDC growth scenario.

Upper North Island generation under all scenarios includes:

- Ngawha, 24 MW
- Glenbrook, 77 MW
- Huntly Unit 6, 40 MW.

5 Methodology

The aim was to find the thermal constraint between Whakamaru and Auckland, under three alternative slack bus[1] location assumptions. The range of slack bus locations was intended to test the robustness of the results for a reasonable range of generation developments.

Modelling was extended to cover forecast load growth to 2030, except where a configuration could not be made to converge in the model. Where this occurred, circuit overloading was so severe that it was clear that further study was not necessary as the scenario was not realistic.

Load growth was modelled based on the forecast used in the 2015 Transmission Planning Report studies. This is Transpower's winter and summer prudent regional load growth forecast.

5.1 Variations

The following variations were modelled:

- Two season assumptions, winter and summer (the forecast load in summer is well below winter, so this season was only considered far enough to demonstrate that the binding constraint will occur in winter).
- Two contingency assumptions: N-1 and N-G-1, and
- Three slack bus assumptions:
    - Stratford ('Taranaki thermal generation development')
    - Haywards ('HVDC development'), and
    - Whakamaru ('Wairakei Ring – geothermal development').

5.2 Reactive support

The following reactive (voltage) support was modelled.

Infinite voltage support at Otahuhu 220 kV, Albany 220 kV and Marsden 220 kV busses (this aligns with the Static Reactive Support investigation).

Infinite voltage support at busses between Bunnythorpe and Huntly sufficient to ensure the models converged. Locations and set points are provided for each case in the Results section (Section 6).

5.3 Variable line ratings

These are in effect on the Otahuhu-Whakamaru-1 and 2 circuits. This means that the circuits have six different ratings across the day, and these change each month. However, only seasonal line ratings were considered in this investigation. In almost all cases, variable line ratings will give slightly more transmission capacity into Auckland than reported here.

The effect of variable line rating will be taken into account when determining a preferred upgrade option and the timing of any investment.

[1] A slack bus is the location where all replacement generation is located, with a generation output automatically set to make up the difference between the load plus losses and the output from all the other generators.

6 Results

6.1 HVDC development scenario

6.1.1 Generation

HVDC injection at Haywards is used to balance increasing load in the North Island. A summary of the load and generation under this scenario is given in Table 6-1. This summary is for the case where Huntly Unit 5 is in service.

Table 6-1: Overview of HVDC scenario load and generation

	2015	2030
UNI Load	2385 MW	2839 MW
Slack (HVDC, Haywards)	1638 MW	2996 MW
NI transmission losses	349 MW	823 MW

Table 6-2: Assumptions for the HVDC scenario

Voltage support location at 220 kV bus	Set point
Marsden	1.0
Albany	1.022
Otahuhu	1.02
Huntly	1.02
Whakamaru	1.026
Tokaanu	1.05
Taumarunui	1.0
Tangiwai	1.025
Bunnythorpe	1.015
Additional generation location	**Injection**
HVDC	Slack bus

6.1.2 HVDC development results

The first N-1 constraint into Auckland is the Otahuhu-Whakamaru-1 and 2 circuits, approaching their thermal limit during an outage of a 220 kV Hamilton-Whakamaru-1 circuit in winter 2030 (see Table 6-3). In summer, the circuits into Auckland are not as constrained as in winter, with the worst case N-1 circuit loading less than 80% by 2030.

In practice, the 220 kV Bunnythorpe-Tokaanu-Whakamaru and Huntly-Stratford circuits are grossly overloaded if all decommissioned generation is replaced by increased HVDC. The North Island system could not be operated without some investment to resolve this.

Table 6-3: HVDC Slack bus with Huntly unit 5 in service

Load	Contingency	Highest loading	Loading %
Winter			
Winter 2030	HAM-WKM-1	OTA-WKM-1 and 2	96
Winter 2030	OHW-WKM-1	HAM-WKM-1	95
Summer			
Summer 2030	OTA-WKM-1	OTA-WKM-2	72
Summer 2030	OTA-WKM-2	OTA-WKM-1	72

The first constraint under an N-G-1 scenario occurs in winter 2022, as shown in Table 6-4.

Table 6-4: HVDC slack bus winter Huntly unit 5 out of service

Load	Contingency	Highest loading	Loading %
Winter 2022	OHW-WKM-1	HAM-WKM-1	101
Winter 2023	HAM-WKM-1	OTA-WKM-1 & 2	100
Winter 2027	HAM-WKM-1	OHW-WKM-1	102
Winter 2030	HAM-WKM-1	OHW-WKM-1	108
Winter 2030	HAM-WKM-1	OTA-WKM-1 & 2	112
Winter 2030	OHW-WKM-1	HAM-WKM-1	116

Table 6-5 indicates that even at N-G-1, there will be no summer constraints until beyond 2030.

Table 6-5: HVDC slack bus summer Huntly unit 5 out of service

Load	Contingency	Highest loading	Loading %
Summer 2027	OTA-WKM-2	OTA-WKM-1	80
Summer 2030	OTA-WKM-2	OTA-WKM-1	82

6.2 Stratford (Taranaki) generation development scenario

This scenario represents generation development in the Taranaki area. This would most likely be gas peaking plant.

Under this scenario, the two Huntly-Stratford circuits are grossly overloaded, as are the Central North Island circuits. For this reason, the analysis was repeated with those circuits upgraded (duplexed) to check for any change to the results.

6.2.1 Stratford slack bus

The HVDC is set to inject 1200 MW at Haywards. The balance is made up from Stratford. Initially, with Huntly Units 1 to 4, Otahuhu and Southdown generation decommissioned and loads at 2015 winter prudent peak, Stratford slack is injecting 469 MW.

Table 6-6: Overview of the Taranaki generation development scenario load and generation

	2015 peak loads	2030 peak loads
No upgrades		
UNI Load	2385 MW	2839 MW
Slack generation (SFD)	469 MW	1885 MW
NI transmission losses	341 MW	872 MW
With upgrades		
UNI Load	2385 MW	2839 MW
Slack generation (SFD)	390 MW	1505 MW
NI transmission losses	261 MW	492 MW

Table 6-7 Assumptions for the Taranaki generation development scenario

Voltage support location	Set point (220 kV bus)
Marsden	1.0
Albany	1.022
Otahuhu	1.02
Huntly	1.02
Whakamaru	1.026
Tokaanu	1.035
Taumarunui	1.0
Stratford	1.03
Bunnythorpe	1.025
Additional generation location	**Injection**
HVDC	1200 MW
System changes	**Notes**
HLY-SFD line upgrade	Duplexed
BPE-TKU-WKM line upgrade	Duplexed

6.2.2 Results without upgrades

The results in Table 6-8 show that transmission constraints do not occur between Whakamaru and Auckland until beyond 2030 under this scenario. However, constraints will exist on the Stratford-Taumarunui and Bunnythorpe-Tokaanu-Whakamaru circuits at peak load periods as soon as all the Huntly Rankine units are decommissioned.

Table 6-8: Taranaki generation development, winter with Huntly unit 5 in service

Load	Contingency	Highest loading	Loading %
Winter 2030	HAM-WKM-1	OTA-WKM-1 and 2	92
Winter 2030	OHW-WKM-1	HAM-WKM-1	89

Table 6-9 shows the loading on the Otahuhu-Whakamaru-1 and 2 circuits under the worst N-G-1 contingency in 2023. This case does not converge after 2023 due to extreme overloading of the Huntly-Stratford and Bunnythorpe-Whakamaru lines (see Table 6-10), which, under this scenario, can exceed N-1 capacity as soon as the generation is decommissioned.

Table 6-9: Taranaki generation development, winter with Huntly unit 5 out of service

Load	Contingency	Highest loading	Loading %
Winter 2023	HAM-WKM-1	OTA-WKM-1 and 2	97

Table 6-10 shows the loading on the circuits between Huntly and Stratford under this scenario. Because of this very high loading, the scenario was repeated with the circuits duplexed to check the sensitivity of results.

Table 6-10: Worst case circuit loading outside the study area

Load	Contingency	Highest loading	Loading %
Winter 2015	HLY-SFD-1	SFD-TMN-1	145
Winter 2015	TKU-WKM-1	TKU-WKM-2	172

6.2.3 Results with upgrades

The analysis was repeated with the Huntly-Stratford line and Central North Island circuits upgraded (duplexed) to check for any change to the results.

As shown in Table 6-11, Otahuhu-Whakamaru-1 and 2 are not overloaded under an N-1 scenario until beyond 2030. Even under an N-G-1 scenario as given in Table 6-12, the Otahuhu-Whakamaru-1 and 2 circuits do not exceed capacity until beyond 2030.

Table 6-11: Taranaki generation development, winter with Huntly unit 5 in service

Load	Contingency	Highest loading	Loading %
Winter 2030	HAM-WKM-1	OTA-WKM-1 and 2	85

Table 6-12: Taranaki generation development, winter, Huntly unit 5 out of service

Load	Contingency	Highest loading	Loading %
Winter 2030	HAM-WKM-1	OTA-WKM-1 and 2	94
Winter 2030	OHW-WKM-1	HAM-WKM-1	92

6.3 Wairakei Ring generation development scenario

This scenario models generation development in the Wairakei area. The slack generator was placed at Whakamaru as a proxy for what is most likely to be geothermal generation development in the area north-east of Taupo.

6.3.1 Results

Table 6-13: Overview of the Wairakei development scenario load and generation

	2015	2030
UNI Load	2385 MW	2839 MW
Slack	352 MW	1305 MW
Losses	263 MW	332 MW

Table 6-14: Assumptions for the Wairakei generation development scenario

Voltage support location	Set point at 220 kV bus
Albany	1.022
Marsden	1.0
Otahuhu	1.02
Huntly	1.02
Whakamaru	1.026
Additional generation location	**Injection**
HVDC	1200 MW

The results of this scenario show the Hamilton-Whakamaru-1 circuit exceeding its capacity under the worst single contingency in 2024. The Otahuhu-Whakamaru-1 and 2 circuits first exceed capacity under N-1 contingency in winter 2025, as shown in Table 6-15.

Table 6-15: Whakamaru slack generation, winter with Huntly unit 5 in service

Load	Contingency	Highest loading	Loading %
Winter 2024	OHW-WKM-1	HAM-WKM-1	100
Winter 2025	HAM-WKM-1	OTA-WKM-1 and 2	101
Winter 2028	HAM-WKM-1	OHW-WKM-1	101
Winter 2030	HAM-WKM-1	OHW-WKM-1	105
Winter 2030	HAM-WKM-1	OTA-WKM-1 and 2	110
Winter 2030	OHW-WKM-1	HAM-WKM-1	114

Table 6-16 shows the worst-case circuit loading if Huntly Unit 5 is out of service (N-G-1).

The worst case is an outage of the Ohinewai-Whakamaru-1 circuit, which results in the Hamilton-Whakamaru-1 circuit supplying Hamilton plus a portion of load into Auckland via Ohinewai.

Table 6-16: Whakamaru slack winter with unit 5 out of service

Load	Contingency	Highest loading	Loading %
Winter 2016	OHW-WKM-1	HAM-WKM-1	102
Winter 2017	HAM-WKM-1	OHW-WKM-1	101
Winter 2017	HAM-WKM-1	OTA-WKM-1 and 2	102
Winter 2017	OHW-WKM-1	HAM-WKM-1	107
Winter 2030	HAM-WKM-1	OHW-WKM-1	130
Winter 2030	HAM-WKM-1	OTA-WKM-1 and 2	128
Winter 2030	OHW-WKM-1	HAM-WKM-1	137

6.4 110 kV network between Arapuni and Otahuhu

As the Arapuni 110 kV bus split is assumed to be retained, there are no new constraints identified on the 110 kV network between Arapuni and Otahuhu that are attributed to the decommissioning of generation in the upper North Island.

There are known (n-1) capacity issues on the Bombay–Wiri–Otahuhu 110 kV circuits due to load growth at Wiri/Bombay and to a lesser extent high generation in Auckland. As an interim solution, we implemented Variable Line Ratings on the Otahuhu–Wiri Tee sections to increase transmission capacity from Otahuhu. The decommissioning of generation at Otahuhu and Southdown will slightly extend the effectiveness of Variable Line Ratings.

We are investigating investment options such as installing an interconnecting transformer at Bombay to secure supply to Wiri/Bombay in the longer term. Any long term investments will take into account the likely generation development scenarios. However, we don't expect future generation developments to have a significant impact on the need for investment to secure supply to Wiri/Bombay in the long term as this is largely driven by load growth. An exception is if there are future generation connections at Bombay or Wiri in the future, we are not aware of any such plans at present.

We have previously indicated that we will close the Arapuni bus split in 2017 to enable the connection of a new substation in the South Waikato. A separate study was done to investigate the impacts on the ability to close the Arapuni 110 kV bus split from 2017 and the findings can be found in the report titled "*UNI Generation Decommissioning – Impact on the Arapuni 110 kV bus split*".

7 Discussion

With the Upper North Island thermal generation decommissioning, there are likely to be thermal constraints on the transmission system between Whakamaru and Auckland before 2030.

The location of new generation development will make a significant difference to the timing of these thermal constraints. If generation development is concentrated around the Wairakei Ring/Whakamaru area, the constraints may bind as soon as that generation appears. If it is concentrated in Taranaki, the thermal constraints north of Whakamaru may not occur until at least the mid-2020s.

Unless new generation develops in Auckland, there are likely to be transmission constraints in parts of the North Island outside of the area covered in this report. The solution to those constraints could have an effect on the constraints found in this investigation.

Taranaki generation development

This development scenario makes the best use of existing circuits between Huntly and Auckland. It directs more power flow from Taranaki into Auckland via Huntly, which relieves the loading on the smaller capacity Otahuhu-Whakamaru-1 and 2 circuits.

However, to take advantage of this benefit, a solution would be required to resolve overloading of the circuits between Stratford and Huntly, as well as the Central North Island.

HVDC development

This development scenario spreads the additional load across all circuits into Auckland, as the increased supply is from the distant Haywards bus. The first circuits to overload are the Otahuhu-Whakamaru-1 and 2 circuits. These circuits are relatively low capacity and are typically one of the first constraints on power supply into Auckland under a range of scenarios.

Replacing the decommissioned generation with South Island generation would require an upgrade to increase the HVDC capacity.

Wairakei Ring generation development

A concentration of new generation in the Wairakei Ring area results in increased power flow through the Otahuhu-Whakamaru-1 and 2 circuits. As these are already quite highly loaded, this development scenario will see transmission constraints before other scenarios.

It is likely that this scenario will result in fewer constraints in the North Island system south of Whakamaru than other generation development scenarios.

Appendix A: DIgSILENT load flow results

The following figures are snapshots of each study case, either at 2030 (i.e. using the forecast 2030 loads) or at the year the first overload occurs. The voltage support that was added to the model to ensure it converged is not shown in these diagrams.

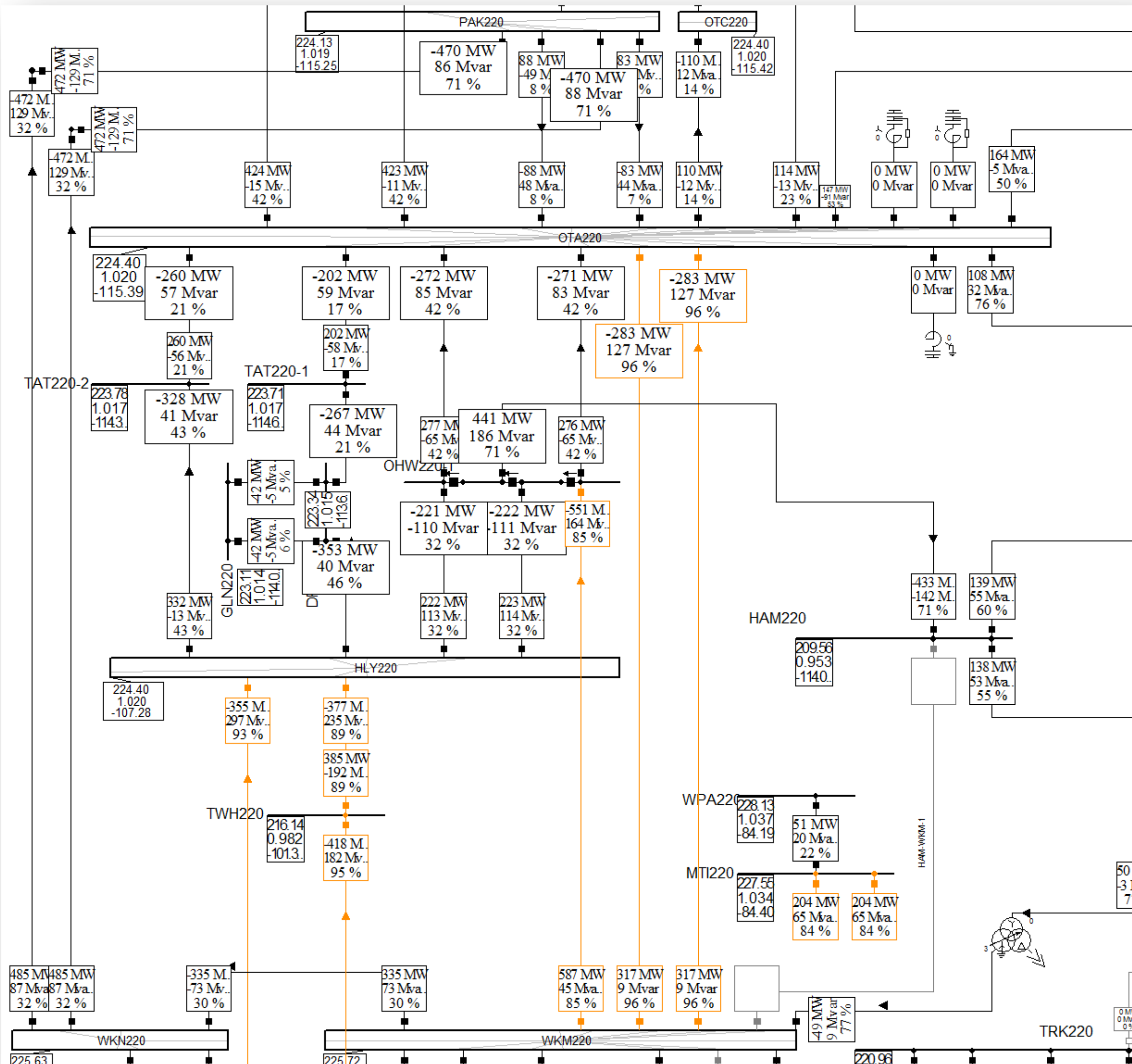


Figure 0-1: HVDC development scenario – worst case N-1 contingency, 2030

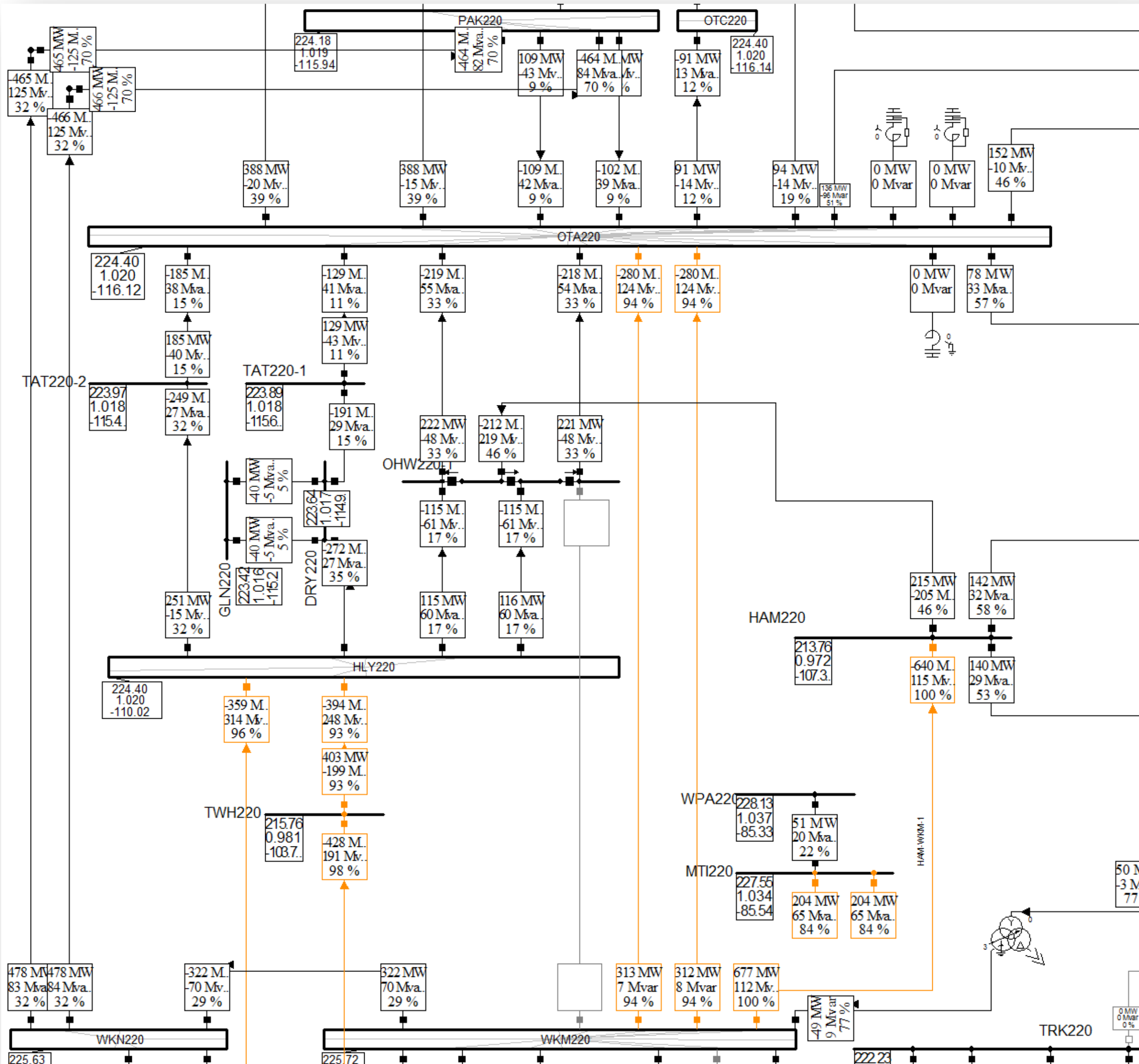


Figure 0-2: HVDC development scenario – worst case N-G-1 contingency, 2022

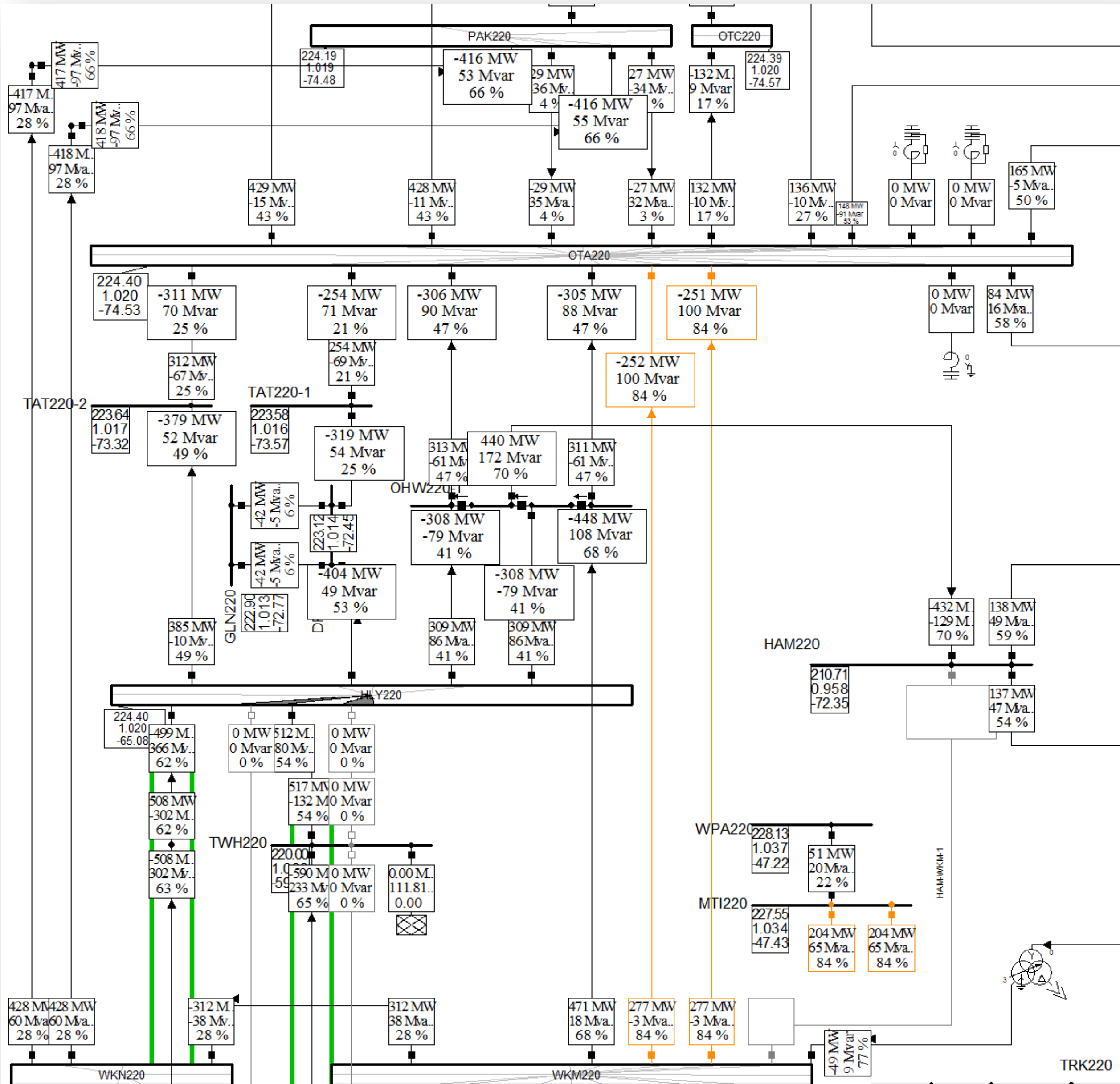


Figure 0-3: Taranaki generation development – worst case N-1 contingency (with Taranaki and CNI circuits upgraded), 2030

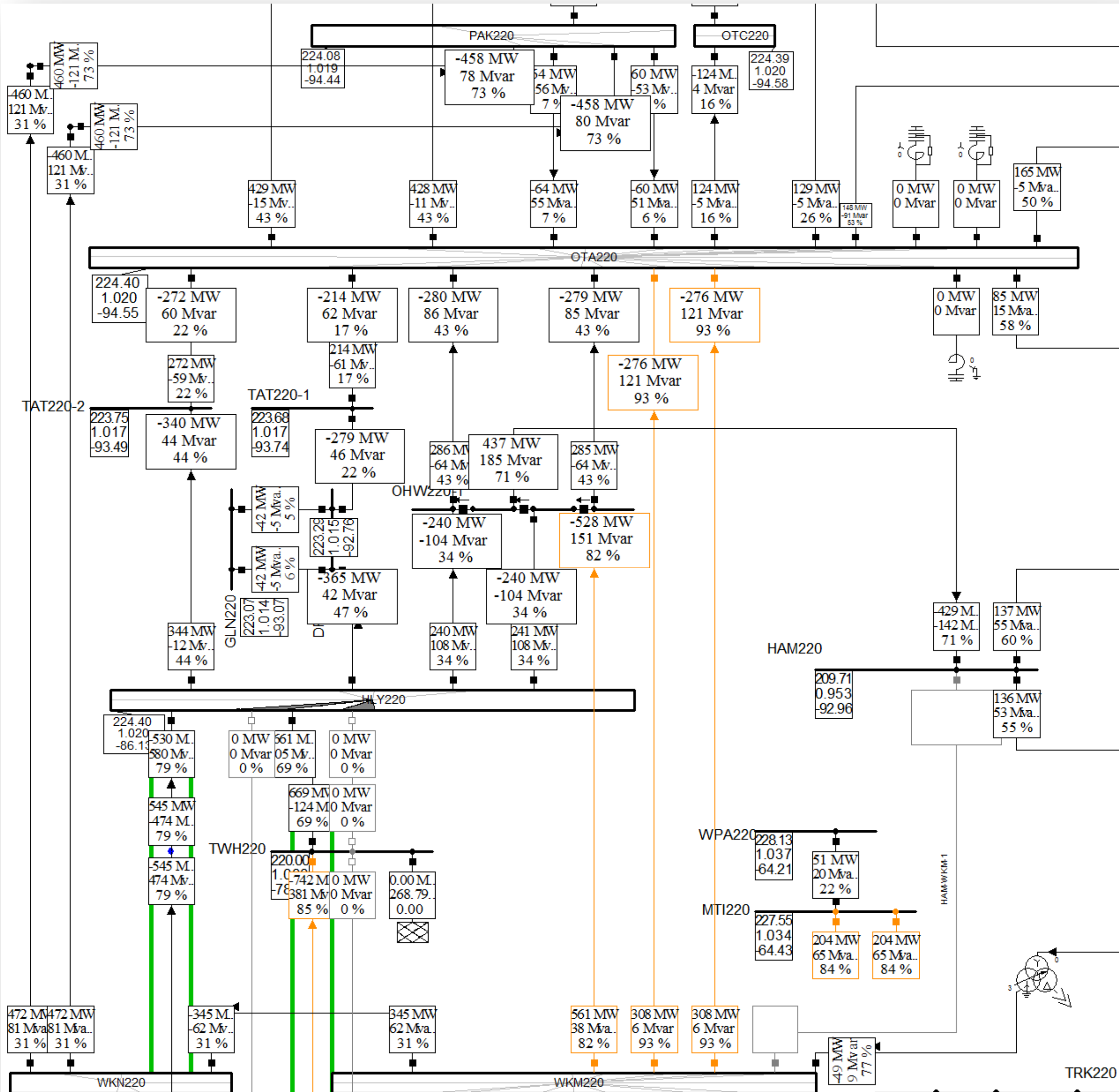


Figure 0-4: Taranaki generation development (circuit upgrades modelled)– worst case N-G-1 contingency, 2030

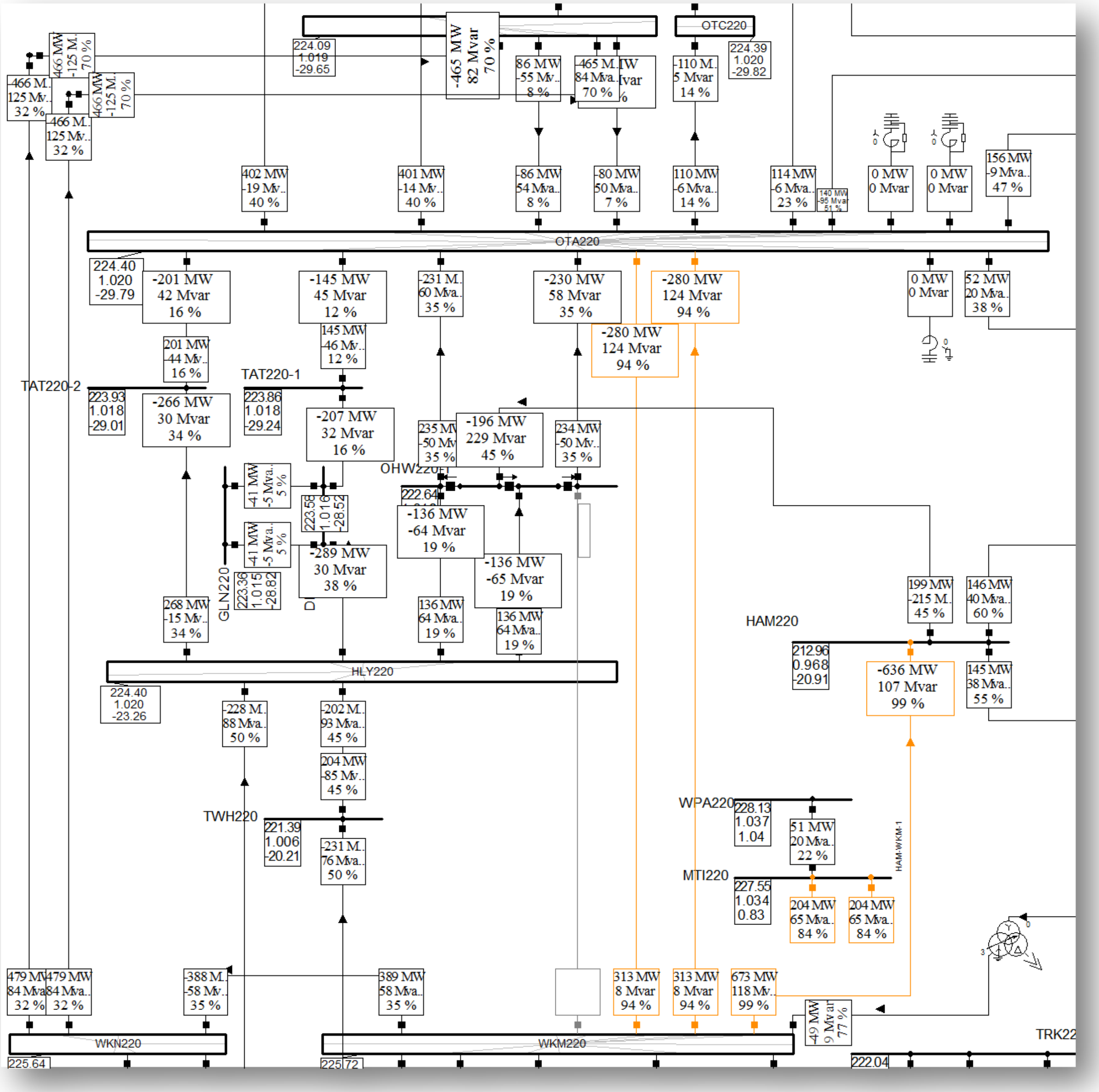


Figure 0-5: Wairakei Ring generation development – worst case N-1 contingency, 2024

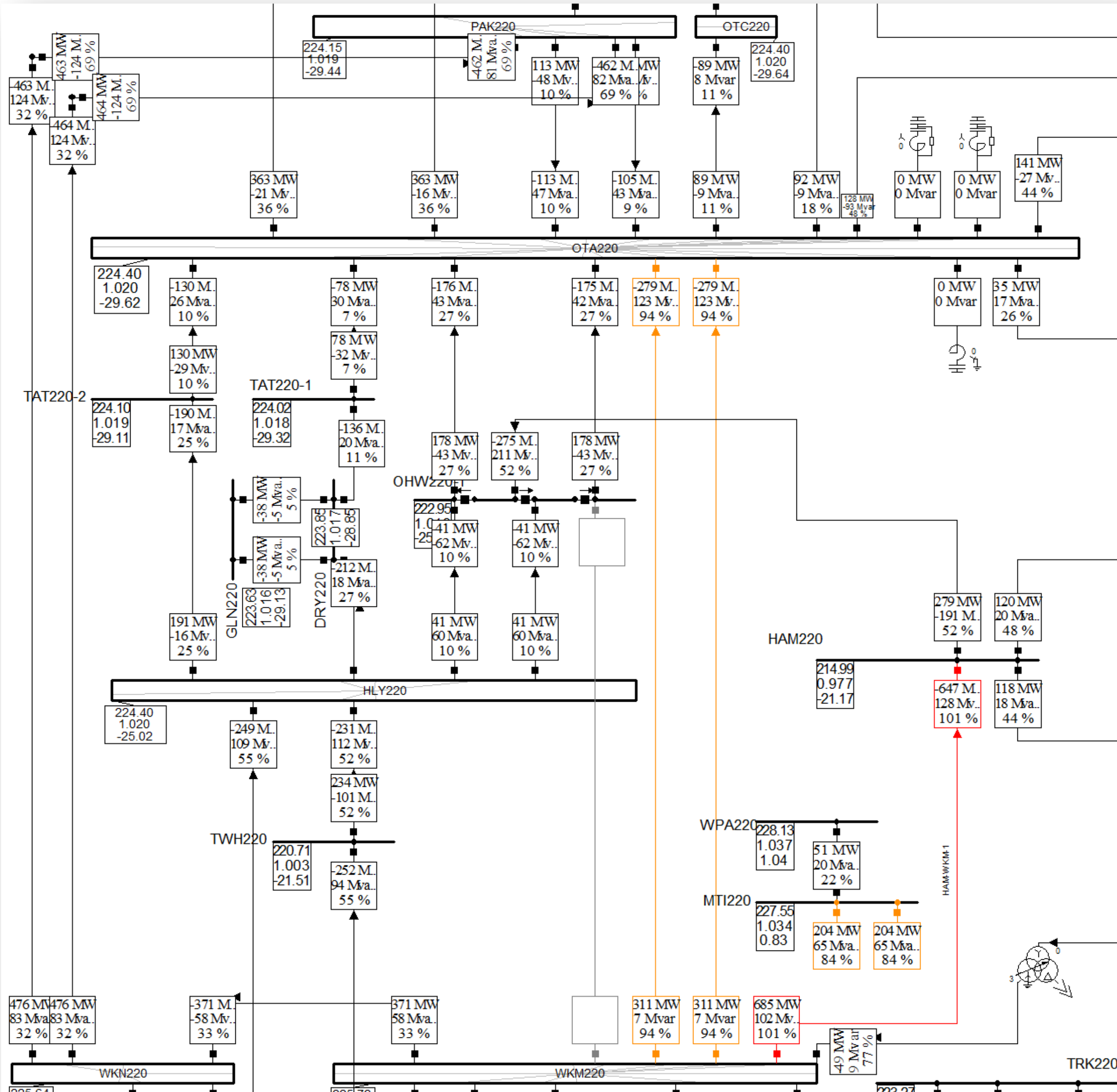


Figure 0-6: Wairakei Ring generation development – worst case N-G-1 contingency, 2016

UNI Generation Decommissioning Report

APPENDIX 4: Transmission Constraints South of Whakamaru

March 2016

Keeping the energy flowing

TRANSPOWER

Transpower New Zealand Limited The National Grid

Table of contents

Executive summary

This report presents the thermal constraints on the transmission network from the major generation centres (Taranaki, Wairakei, Bay of Plenty, and Wellington) into Whakamaru and Huntly.

The purpose of this investigation was to identify the transmission constraints if the decommissioned Auckland and Huntly generation is replaced by generation from regions south of Whakamaru. This investigation only covers the transmission network from these regions into Whakamaru and Huntly. This report is part of a suite of reports on the impact of decommissioning thermal generation in the upper North Island.

The results of the investigation showed that as soon as the two remaining Rankine units (unit 1 and unit 2) are decommissioned at Huntly we cannot supply the North Island peak load unless new generation is installed at or north of Whakamaru. There is inadequate transmission capacity south of Huntly and Whakamaru to replace all of the decommissioned generation from high generation potential areas south of Whakamaru.

The North Island peak load cannot be supplied because of the following constraints south of Whakamaru.

- The existing generation in the Taranaki and Wellington regions is constrained by the thermal capacity of the 110 kV Bunnythorpe–Mataroa–1 circuit.
- After the Bunnythorpe–Mataroa–1 constraint, the Tokaanu–Whakamaru–1 and 2 and Huntly–Stratford–1 circuits are the next limiting circuits. The thermal rating of these circuits will also limit the existing generation in the Wellington and Taranaki regions.

Although there are no constraints on existing generation in the Bay of Plenty, Wairakei, and Hawkes Bay areas during peak loads, there is limited capacity to connect additional generation.

- Up to 120 MW of additional generation can be installed at Wairakei before the Atiamuri–Ohakuri–1 circuit will constrain generation.
- Alternatively up to 100 MW of additional generation can be installed at Kawerau (220 kV) before the thermal capacity of the Atiamuri–Ohakuri–1 circuit will constrain generation.

1 Purpose of this document

The purpose of this report is to present the thermal transmission constraints between the major generation centres (Taranaki, Wairakei, Bay of Plenty, and Wellington) and Whakamaru and Huntly.

2 Introduction

2.1 Purpose of the investigation

The existing transmission network between Bunnythorpe and Huntly is shown schematically in Figure 2-1.

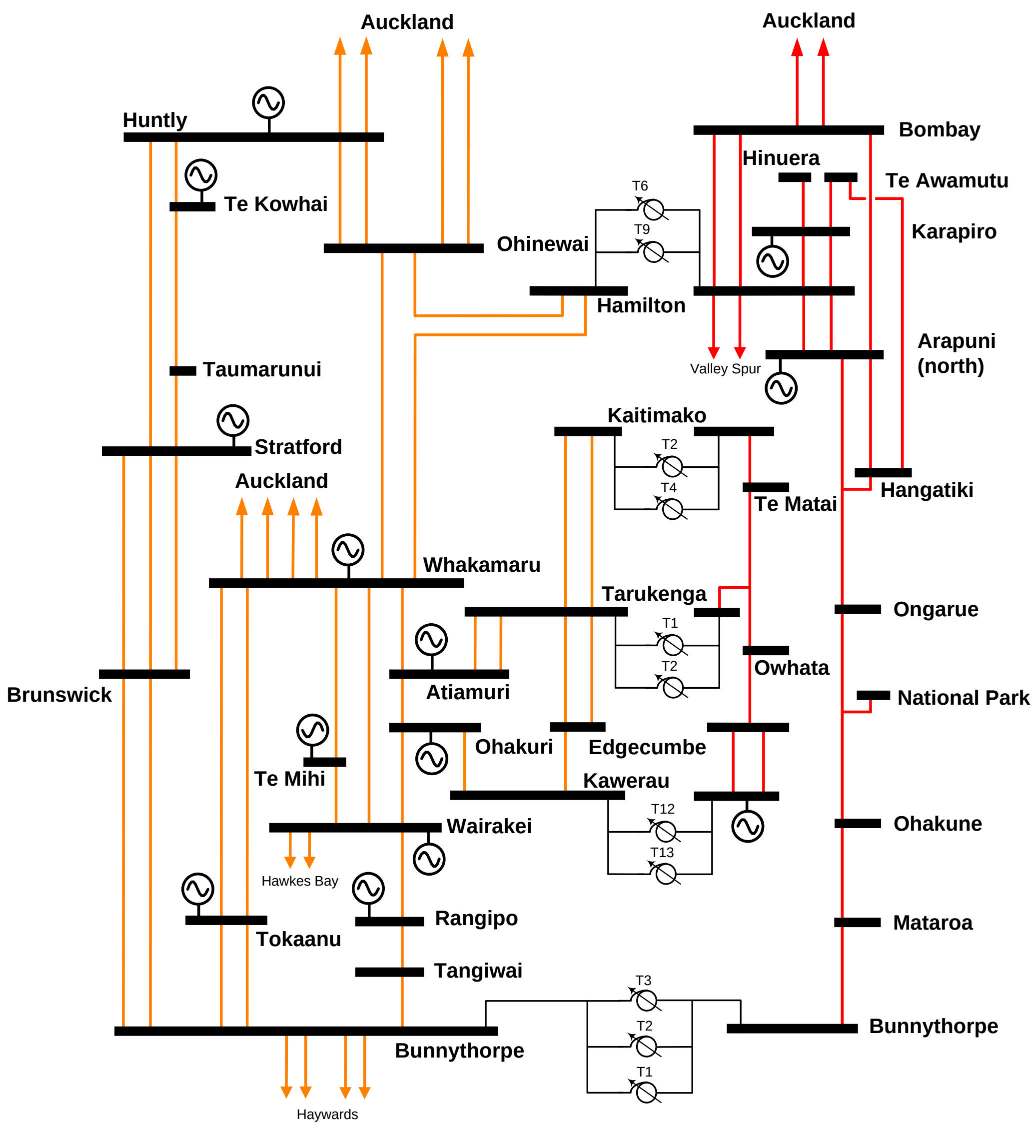


Figure 2-1 Schematic of transmission grid between Bunnythorpe and Huntly (spurs omitted)

With the reduction of generation capacity at Huntly and the Auckland region, more generation will be required from the other regions to supply the upper North Island load. There needs to be sufficient transmission capacity from these regions to Huntly and Whakamaru to supply the upper North Island.

The purpose of this investigation was to identify the transmission constraints if the decommissioned Auckland and Huntly generation is replaced by generation from the generation rich regions south of Whakamaru. This investigation only covers the transmission network from these regions into Whakamaru and Huntly where the main transmission lines that supply the upper North Island are. Other reports cover the transmission capacity from Whakamaru and Huntly to Auckland, and other transmission issues due to decommissioning thermal generation. The areas with generation are:

- Taranaki (equivalent generation modelled on the Stratford 220 kV bus)
- Wellington including the HVDC (equivalent generation modelled using the HVDC)
- Wairakei including the Hawkes Bay (equivalent generation modeled on the Wairakei 220 kV bus)
- Bay of Plenty, extends to the Arapuni South bus (equivalent generation modeled on the Kawerau 220 kV bus to represent potential generation developments in the Kawerau area)

Table 2-1 lists the major circuits that connect the regions with generation to Whakamaru and Huntly.

Table 2-1: Details of circuits between Bunnythorpe and Huntly

Circuit	Voltage [kV]	Main Conductor	Conductor Rating Summer	Conductor Rating Winter
Huntly–Stratford–1	220	ZebraGZ at 120°C	354 MVA, 930 A	354 MVA, 930 A[1]
Huntly–Te Kowhai–1	220	ZebraGZ at 120°C	469 MVA, 1231 A	492 MVA, 1292 A[2]
Taumarunui–Te Kowhai–1	220	ZebraGZ at 120°C	469 MVA, 1231 A	492 MVA, 1292 A
Stratford–Taumarunui–1	220	ZebraGZ at 120°C	469 MVA, 1231 A	492 MVA, 1292 A
Brunswick–Stratford–1, 2, and 3	220	ZebraGZ at 48.9°C	233 MVA, 610 A	286 MVA, 752 A
Bunnythorpe–Brunswick–1	220	Duplex ZebraGZ at 75°C	694 MVA, 1822 A	762 MVA, 2000 A[3]
Bunnythorpe–Brunswick–2	220	Duplex ZebraGZ at 75°C	694 MVA, 1822 A	713 MVA, 1870 A[4]
Bunnythorpe–Tokaanu–1 and 2	220	GoatGZ at 80°C	308 MVA, 807 A	335 MVA, 880 A
Bunnythorpe–Tangiwai–1	220	ZebraGZ at 50°C	239 MVA, 627 A	291 MVA, 765 A
Tokaanu–Whakamaru–1 and 2	220	GoatGZ at 80°C	308 MVA, 807 A	335 MVA, 880 A
Rangipo–Tangiwai–1	220	ZebraGZ at 50°C	239 MVA, 627 A	291 MVA, 765 A
Rangipo–Wairakei–1	220	ZebraGZ at 80°C	364 MVA, 955 A	397 MVA, 1042 A
Ohakuri–Wairakei–1	220	GoatGZ at 90°C	VLR	VLR[5]
Atiamuri–Ohakuri–1	220	GoatGZ at 90°C	VLR	VLR[6]
Atiamuri–Whakamaru–1	220	GoatGZ at 90°C	333 MVA, 874 A	358 MVA, 940 A
Kawerau–Ohakuri–1	220	ZebraGZ at 50°C	239 MVA, 627 A	291 MVA, 765 A
Edgecumbe–Kawerau–3	220	ZebraGZ at 50°C	239 MVA, 627 A	291 MVA, 765 A
Bunnythorpe–Mataroa–1	110	Cu 19/2.57 at 50°C	57 MVA, 300 A	70 MVA, 366 A
Edgecumbe–Kawerau–1	110	HareGZ at 50°C	48 MVA, 253 A	59 MVA, 309 A
Edgecumbe–Kawerau–2	110	DogGZ at 50°C	48 MVA, 253 A	59 MVA, 309 A
Edgecumbe–Owhata–2	110	PartridgeGZ at 50°C	57 MVA, 298 A	69 MVA, 364 A
Mataroa–Ohakune–1	110	Cu 19/2.57 at 50°C	57 MVA, 300 A	70 MVA, 366 A
Ohakune–National Park–Ongarue–1	110	Cu 19/2.57 at 50°C	57 MVA, 300 A	70 MVA, 366 A
Arapuni–Hangatiki–Ongarue–1	110	Cu 19/2.57 at 50°C	57 MVA, 300 A	70 MVA, 366 A[7]

1. Limited by protection equipment, main summer/winter conductor ratings are 469/492 MVA, 1231/1292 A
2. Forward branch limit (i.e. power flow from Huntly to Te Kowhai) is limited by protection equipment to 301 MVA, 790 A
3. Winter rating limited by current transformer, main conductor winter rating is 764 MVA, 2006 A
4. Winter and shoulder rating limited by bus equipment at Bunnythorpe, main conductor winter rating is 764 MVA, 2006 A
5. Variable line ratings are applied to Ohakuri–Wairakei. Lowest summer rating is 333 MVA, 874 A and lowest winter rating is 361 MVA, 947 A
6. Variable line ratings are applied to Atiamuri–Whakamaru. Lowest summer rating is 343 MVA, 901 A and lowest winter rating is 363 MVA, 953 A
7. Forward branch limit (i.e. power flow from Arapuni to Hangatiki/Ongarue) is limited by protection to 69 MVA, 364 A.

2.2 Scope of the investigation

The scope of this investigation was to identify the transmission constraints from the four areas with generation potential to Whakamaru and Huntly. Only the constraints for north flow scenarios are presented. The investigation is intended to determine the transmission constraints if generation from other regions replaces the decommissioned Auckland and Huntly generation.

This investigation does not include investment options as this will be covered by a separate study.

2.3 Thermal generation decommissioning

The thermal generators that are decommissioned for this analysis are:

- Otahuhu combined cycle (380 MW, decommissioned)
- Southdown combined cycle (175 MW, decommissioned)
- Huntly Rankine units 1 and 2 (250 MW each, to be decommissioned by December 2018, unless market conditions change).

In total, 1,055 MW of thermal generation will be decommissioned by the end of December 2018. This is in addition to the already decommissioned Huntly Rankine units 3 and 4 (250 MW each).

2.4 Outline of the document

In this report:

Chapter 1 ‘

- Purpose of this document' describes the purpose of this report
- Chapter 2 'Introduction' introduces the purpose of the study and defines the scope of the investigation
- Chapter 3 presents the constraints for generation export from the Wellington and Taranaki regions.
- Chapter 4 presents the constraints for generation export from the Wairakei and Bay of Plenty areas.

3 Generation export from Taranaki and Wellington

Generation from the Taranaki and Wellington[1] regions needs to be transferred to Whakamaru and Huntly to supply the Upper North Island. The main transmission lines are the Huntly–Stratford, Bunnythorpe–Tokaanu–Whakamaru, and Bunnythorpe–Tangiwai–Rangipo–Wairakei. The low capacity 110 kV circuit between Arapuni and Bunnythorpe is paralleled with these main 220 kV transmission lines with interconnection points at Bunnythorpe and Hamilton.

The Wellington and Taranaki regions are linked by relatively high capacity 220 kV circuits between Bunnythorpe and Stratford (see network schematic Figure 2-1). Therefore increasing generation in one region will affect generation export limits in the other region.

The analysis in this section tests the maximum generation allowed in one region if the other region's generation is at maximum. The purpose of this analysis is to provide some indication of the existing grid's capability[2] to use generation from Taranaki and Wellington to supply the upper North Island.

3.1 Existing generation constraints

It is well documented that the Bunnythorpe–Mataroa–1 110 kV circuit is the first binding constraint for generation export from the Taranaki and Wellington regions. The worst case circuit contingency is the 220 kV Hamilton–Whakamaru–1 circuit. This circuit contingency increases the power flow from Bunnythorpe to Hamilton through the 110 kV network.

3.1.1 Winter peak

The specific assumptions in this scenario are:

- North Island winter peak load (prudent)
- Maximum Taranaki generation is 788 MW in 2018 and 888 MW from 2020
- Maximum Wellington generation is 1524 MW (HVDC north transfer at 1000 MW, lower North Island wind at 499 MW, and Mangahao at 25 MW)
- Huntly generation at 440 MW
- Arapuni North generation at 117 MW and Karapiro generation at 96 MW
- Maximum North Island hydro and central North Island geothermal generation.

With maximum Taranaki generation the HVDC north flow is backed off to remove overloads on the Bunnythorpe–Mataroa–1 circuit. The maximum generation allowed in the Wellington region during the 2018 winter peak load period is1220 MW, reducing to 1125 MW by winter 2020. The reduction is due to increasing loads on the 110 kV network which increases north flow on the 110 kV Bunnythorpe–Mataroa–1 circuit.

This limit indicates that around 300 MW of existing generation in the Wellington area cannot be used to supply the upper North Island if Taranaki is operating at installed capacity, Instead an additional 110 MW of generation is required at Whakamaru to meet the load.

With maximum Wellington generation, generation at Stratford is backed off to remove overloads on the Bunnythorpe–Mataroa–1 circuit. The maximum generation allowed in the Taranaki region during the 2018 winter peak load period is 325 MW, reducing to 290 MW by winter 2020.

This limit indicates that around 463 MW of generation in the Taranaki region cannot be used to supply the upper North Island if Wellington is operating at 1524 MW (close to installed

[1] The Wellington region generation includes the South Island generation which is modelled as HVDC north flow. All lower North Island wind generation is also considered as Wellington generation.

[2] See Section 5.1.3 for the committed projects that are included as the existing grid.

capacity). Instead an additional 200 MW of generation is required at Whakamaru to meet the load.

In summary the thermal rating of the Bunnythorpe–Mataroa–1 circuit prevents us from using the full capacity of existing generation in the Taranaki and Wellington regions to meet the load in the Upper North Island. Figure 3-1 shows the generation limits in the Wellington and Taranaki regions during winter (prudent) peak load periods.

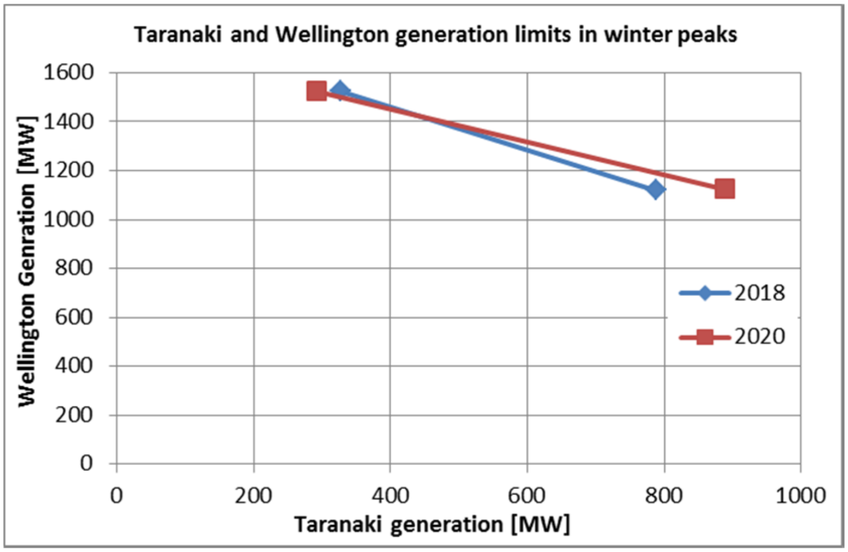


Figure 3-1: Wellington vs Taranaki generation limits during North Island winter peak load

3.1.2 Summer peak

The specific assumptions in this scenario are:

- North Island summer peak load (prudent)
- Maximum Taranaki generation is 888 MW.
- Maximum Wellington generation is 1324 MW (HVDC north transfer at 800 MW, lower North Island wind at 499 MW, and Mangahao at 25 MW)
- Huntly generation at 40 MW (Unit 5 unavailable)
- Arapuni North generation at 117 MW and Karapiro generation at 96 MW
- Maximum North Island hydro and central North Island geothermal generation.

With maximum Taranaki generation, the HVDC north flow is backed off to remove overloads on the Bunnythorpe–Mataroa–1 circuit. The maximum generation allowed in the Wellington region during the 2018 summer peak load period is: 730 MW, reducing to 715 MW by summer 2020.

There is sufficient generation to supply the summer peak loads (up to 2020) without exceeding the Wellington generation limits.

With maximum Wellington generation, generation at Stratford is backed off to remove overloads on the Bunnythorpe–Mataroa–1 circuit. The maximum generation allowed in the Taranaki region during 2018 summer peak load period is 25 MW in 2018, from 2020, the Bunnythorpe–Mataroa–1 constraint binds even without Taranaki generation.

This limit indicates that around 763 MW of existing generation in the Taranaki area cannot be used to supply the upper North Island if Wellington is operating at 1324 MW. Instead an additional 70 MW of generation is required at Whakamaru to meet the load.

In summary the thermal rating of the Bunnythorpe–Mataroa–1 circuit prevents us from using the full capacity of existing generation in the Taranaki and Wellington regions to meet the load in the Upper North Island. Figure 3-2 shows the generation limits in the Wellington and Taranaki regions during summer (prudent) peak load periods.

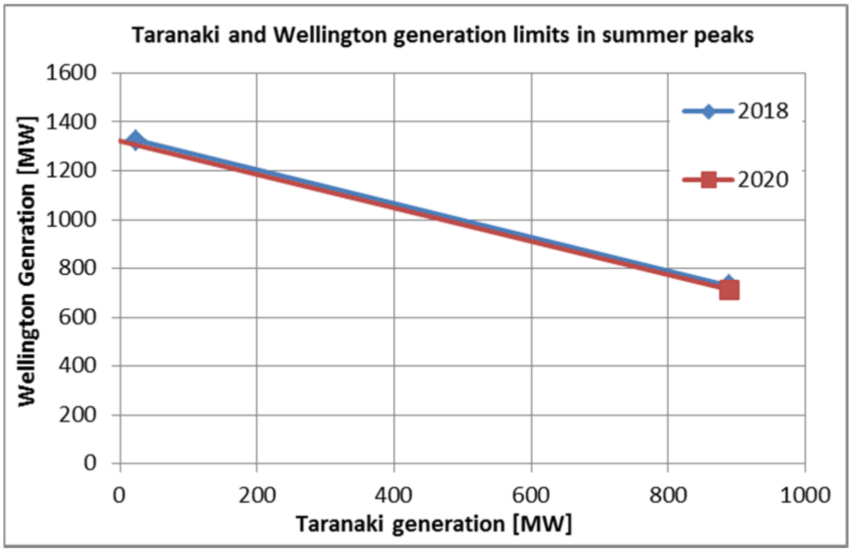


Figure 3-2: Wellington vs Taranaki generation limits during North Island summer peak load

3.2 Constraints following the Bunnythorpe–Mataroa constraint

This section discusses the binding transmission constraints after the Bunnythorpe–Mataroa constraint. Generation limits are not provided for in this section as it differs depending on the preferred solution for resolving the Bunnythorpe–Mataroa–1 circuit constraint.

To identify the next binding constraint, the Bunnythorpe–Mataroa–1 circuit is opened when it's overloaded post contingency. This option is selected purely for the purposes of studying the next transmission constraint and may not be the preferred solution[3].

In summary, the next generation export constraints for the Taranaki and Wellington regions are the Tokaanu–Whakamaru–1 and 2 and Huntly–Stratford–1 circuits. These two constraints are very close to each other therefore resolving just one of the constraints will not provide a large increase in transmission limits out of these regions.

Table 3-1 shows the next binding constraints for generation in the Taranaki and Wellington regions if the Bunnythorpe–Mataroa–1 overload scheme is installed. The constraints are calculated by dispatching maximum generation in one region (underlined in the table) and then increasing generation in the other region until a circuit overloads post-contingency.

The generation limits are calculated with the slack bus at Whakamaru, these values may vary slightly depending on where additional generation is placed. In winter scenarios up to 5 MW of additional generation is required at or north of Whakamaru to supply the load north of Whakamaru, increasing to about 145 MW by 2020.

The generation limits for 2018 assume the last two Rankine units (units 1 and 2) are decommissioned.

There were no additional generation requirements for any of the summer cases.

[3] A separate study is underway to determine the preferred solution for resolving the Bunnythorpe–Mataroa constraint (includes the technical and economic evaluations of the short listed options).

Table 3-1: Next binding constraints for generation in the Taranaki and Wellington regions

Case	Wellington generation [MW]	Taranaki generation [MW]	Maximum loaded circuit	Worst contingency
Winter 2018	1345	788	Tokaanu–Whakamaru–1 or 2	Tokaanu–Whakamaru–1 or 2 (Tokaanu Bus Splitting and Bunnythorpe–Mataroa Overload special protection schemes operated)
Winter 2018	1524	546	Tokaanu–Whakamaru–1 or 2	Tokaanu–Whakamaru–1 or 2 (Tokaanu Bus Splitting and Bunnythorpe–Mataroa Overload special protection schemes operated)
Summer 2018	871	888	Tokaanu–Whakamaru–1 or 2	Tokaanu–Whakamaru–1 or 2 (Tokaanu Bus Splitting and Bunnythorpe–Mataroa Overload special protection schemes operated)
Summer 2018	1324	310	Tokaanu–Whakamaru–1 or 2	Tokaanu–Whakamaru–1 or 2 (Tokaanu Bus Splitting and Bunnythorpe–Mataroa Overload special protection schemes operated)
Winter 2020	1269	888	Huntly–Stratford–1	Stratford–Taumarunui–1
Winter 2020	1524	603	Tokaanu–Whakamaru–1 or 2	Tokaanu–Whakamaru–1 or 2 (Tokaanu Bus Splitting and Bunnythorpe–Mataroa Overload special protection schemes operated)
Summer 2020	899	888	Tokaanu–Whakamaru–1 or 2	Tokaanu–Whakamaru–1 or 2 (Tokaanu Bus Splitting and Bunnythorpe–Mataroa Overload special protection schemes operated)
Summer 2020	1324	344	Tokaanu–Whakamaru–1 or 2	Tokaanu–Whakamaru–1 or 2 (Tokaanu Bus Splitting and Bunnythorpe–Mataroa Overload special protection schemes operated)

4 Generation export from Wairakei and Bay of Plenty

Generation in the Wairakei/Hawkes Bay[4] and Bay of Plenty areas needs to be transferred to Whakamaru to supply the upper North Island. There are three 220 kV circuits that connect Wairakei to Whakamaru and these circuits are known collectively as the Wairakei ring. The Wairakei ring connects the central North Island geothermal and the Bay of Plenty region to Whakamaru and the rest of the National Grid.

With the existing grid, there are no generation constraints in the Wairakei and Bay of Plenty areas during peak load periods with all equipment in service. Therefore, the analysis in this section will identify the binding constraints if new generation appeared in the Wairakei or Bay of Plenty regions.

- new Wairakei/Hawkes Bay generation is modelled at the Wairakei 220 kV bus
- new Bay of Plenty generation is modelled at the Kawerau 220 kV bus.

The Bay of Plenty region generation is modelled at Kawerau to represent potential geothermal developments around Kawerau (Eastern Bay of Plenty). Generation developments in other areas of the Bay of Plenty region will affect the grid slightly differently.

The generation limits in the Wairakei, Hawkes Bay, and Bay of Plenty areas aren't necessarily affected by the upper North Island generation decommissioning but are discussed here for completeness.

4.1 Constraints for connecting additional generation in Wairakei/Hawkes Bay

4.1.1 Winter peak

The specific assumptions in this scenario are:

- North Island winter peak load (prudent)
- Taranaki generation is 788 MW in 2018 and 888 MW from 2020.
- HVDC north transfer at 1000 MW
- North Island wind contribution is at 20% of installed capacity
- Huntly generation at 440 MW
- Maximum North Island hydro and geothermal generation.
- Maximum embedded generation in the Bay of Plenty and Wairakei
- Arapuni South generation at 65 MW and Kinleith generation at 39 MW
- Whirinaki generation is not in service.

The maximum generation at Wairakei/Hawkes Bay during the winter peak load period is calculated by increasing generation on the Wairakei 220 kV bus and varying generation at Whakamaru.

The binding constraint observed was always overloading of the Atiamuri–Ohakuri circuit following a contingency on the Te Mihi–Whakamaru–1 circuit. This constraint is followed closely by the overloading of the Atiamuri–Whakamaru–1 circuit for the same contingency.

The analysis shows that about 125 MW of new generation can be connected to the Wairakei 220 kV bus without causing capacity issues in the Wairakei Ring during winter peak load periods (this is based on seasonal ratings). This also assumes that up to 80 MW of additional generation required is connected at or north of Whakamaru to supply the load north of Whakamaru.

[4] The Hawkes Bay region is connected by two 220 kV circuits from the Wairakei 220 kV bus. Therefore, new generation in the Hawkes Bay region is also equivalent to generation at Wairakei when studying capacity issues in the Wairakei ring.

Variable Line Ratings (VLR) has been implemented on the Te Mihi–Whakamaru–1 and Atiamuri–Ohakuri–1 circuits which increase their capacity (compared to the summer/shoulder/winter seasonal ratings that are usually applied). VLR will increase the maximum generation capacity and the actual capacity will depend on the time of day and month of year as VLR provides 72 ratings a year.

4.1.2 Summer peak

The specific assumptions in this scenario are:

- North Island summer peak load (prudent)
- Taranaki generation at 488 MW.
- HVDC north transfer at 700 MW
- North Island wind contribution is at 20% of installed capacity
- Huntly generation at 40 MW
- Maximum North Island hydro and geothermal generation.
- Maximum embedded generation in the Bay of Plenty and Wairakei
- Arapuni South generation at 65 MW and Kinleith generation at 39 MW
- Whirinaki generation is not in service.

The maximum generation at Wairakei/Hawkes Bay during the summer peak load period is calculated by increasing generation on the Wairakei 220 kV bus with the slack bus at Whakamaru.

The binding constraint observed was always overloading of the Atiamuri–Ohakuri–1 circuit following a contingency on the Te Mihi–Whakamaru–1 circuit. This constraint is followed closely by the overloading of the Atiamuri–Whakamaru–1 circuit for the same contingency.

The analysis shows that about 120 MW of new generation can be connected to the Wairakei 220 kV bus without causing capacity issues in the Wairakei Ring during summer peak load periods (this is based on seasonal ratings). Up to 55 MW of additional generation was also required at or north of Whakamaru to supply the load north of Whakamaru.

4.2 Constraints for connecting additional generation in the Eastern Bay of Plenty

In addition to the grid backbone constraints discussed below, there are also local constraints for generation connections on the Kawerau 110 kV or 11 kV bus that are well documented in previous Transmission Planning Reports. This analysis assumes the new generation is connected to the Kawerau 220 kV bus, therefore, the issues discussed in the 2015 Transmission Planning Report are not replicated in this analysis.

The two local issues at Kawerau that limits the connection of new generation are:

1. Excessive fault levels on the Kawerau 11 kV distribution bus
2. N-1 thermal constraints on the Kawerau interconnecting transformers which limit the post contingency generation export capacity from the 110 kV to the 220 kV network.

4.2.1 Winter peak

The specific assumptions in this scenario are:

- North Island winter peak load (prudent)
- Taranaki generation is 788 MW in 2018 and 888 MW from 2020
- HVDC north transfer at 1000 MW
- North Island wind contribution is at 20% of installed capacity
- Huntly generation at 440 MW
- Maximum North Island hydro and geothermal generation.
- Maximum embedded generation in the Bay of Plenty and Wairakei

- Arapuni South generation at 65 MW and Kinleith generation at 39 MW
- Whirinaki generation is not in service.

The maximum generation in the Bay of Plenty during the winter peak load period is calculated by increasing generation on the Kawerau 220 kV bus and reducing generation at Whakamaru.

The binding constraint observed was always overloading of the 110 kV Edgecumbe–Owhata–2 circuit following a contingency on the 220 kV Edgecumbe–Kawerau–3 circuit. There is a special protection scheme that opens the Edgecumbe–Owhata–2 circuit when overloaded. However, the operation of this scheme (following an Edgecumbe–Kawerau–3 contingency) may cause an overload on the Atiamuri–Ohakuri–1 circuit in the Wairakei ring, depending on the generation dispatch within the Wairakei ring[5].

The analysis shows that up to 110 MW of new generation can be added at the Kawerau 220 kV bus in 2018 without causing the Edgecumbe–Owhata SPS to operate during winter peak load periods. However, the capacity will decrease as the Bay of Plenty loads north of Kawerau increases[6], dropping to a maximum of 100 MW by 2020.

Also, the capacity for new generation at Kawerau will reduce when the Bay of Plenty generation north of Kawerau decreases as this causes higher power flows on the constraining Edgecumbe–Owhata–2 circuit[7]. For example, if the generation at Arapuni South or Kinleith is reduced by 1 MW, the amount of new generation that can be connected at Kawerau will decrease by about 0.7 MW.

The next constraints following the Wairakei Ring capacity are:

- Kawerau–Ohakuri–1 circuit overloading for a Edgecumbe–Kawerau–3 contingency
- Edgecumbe–Kawerau–3 circuit overloading for a Kawerau–Ohakuri–1 contingency.

An additional 60-100 MW of new generation can be added at Kawerau before these constraints bind.

4.2.2 Summer peak

The specific assumptions in this scenario are:

- North Island summer peak load (prudent)
- Taranaki generation at 488 MW.
- HVDC north transfer at 700 MW
- North Island wind contribution is at 20% of installed capacity
- Huntly generation at 40 MW
- Maximum North Island hydro and geothermal generation.
- Maximum embedded generation in the Bay of Plenty and Wairakei
- Arapuni South generation at 65 MW and Kinleith generation at 39 MW
- Whirinaki generation is not in service.

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5 The tripping of Edgecumbe–Kawerau–3 and Edgecumbe–Owhata–2 means that all of the generation at Kawerau is only connected to Ohakuri. This causes more power to flow north on the Atiamuri–Ohakuri–1 circuit causing it to overload if Wairakei generation is high.

6 As the Bay of Plenty loads north of Kawerau increases, it “pulls” more power through the low capacity 110 kV Edgecumbe–Owhata–2 circuit from the generators at Kawerau, therefore constraining the maximum generation capacity at Kawerau.

7 Bay of Plenty generation north of Kawerau, especially generation at Kinleith or Arapuni, “blocks” power flow on the low capacity 110 kV Edgecumbe–Owhata–2 circuit. Therefore, as generation north of Kawerau decreases, more Kawerau generation flows through the Edgecumbe–Owhata–2 circuit which constrains the maximum generation capacity at Kawerau.

The maximum generation in the Bay of Plenty region during the summer peak load period is calculated by increasing generation on the Kawerau 220 kV bus and reducing generation at Whakamaru.

Similarly to the winter peak load constraints discussed in Section 4.2.1, the binding constraint observed during the summer peak load period was always overloading of the 110 kV Edgecumbe–Owhata–2 circuit following a contingency on the 220 kV Edgecumbe–Kawerau–3 circuit.

The analysis shows that up to 100 MW of new generation can be added at the Kawerau 220 kV bus in 2018 without causing constraints on the transmission grid backbone during summer peak load periods. However, the capacity will decrease as the Bay of Plenty regional loads increase, dropping to a maximum of 90 MW by 2020.

The effects of reduced generation in the Bay of Plenty region and the next set of constraints are same to those discussed in Section 4.2.1.

5 Assumptions

5.1 Demand Forecast

The analysis used the 2015 Transmission Planning Report demand forecast.

5.1.1 Generation Assumptions

The analysis assumed the following generation has been decommissioned:

- Otahuhu combined cycle
- Southdown power station
- Huntly coal units 1-4

5.1.2 Voltage Support assumptions

The analysis assumed all existing reactive support equipment is available.

5.1.3 Grid planning assumptions

The analysis assumed the Arapuni 110 kV bus split is retained and:

- Arapuni G1-G5 are selected to the Arapuni north bus
- Arapuni G6-G8 are selected to the Arapuni south bus

The 110 kV Hangatiki–Te Awamutu circuit (owned by Waipa Networks) is normally in service.

Powerco's new Putaruru substation is connected from 2018 and is connected to the Arapuni–Kinleith–2 circuit deviation.

The Hawera Substation Upgrade project is assumed to be completed and the 110 kV Hawera–Stratford –1 circuit rating is no longer constrained by the bus section to 400 A. The circuits' summer/winter ratings are 805/866 A, limited by its main conductor which is Nobelium AAAC with a designed sag temperature of 90°C.

5.2 Special Protection Schemes

The following is a brief description of the special protection schemes (SPS) that are relevant to the investigation.

5.2.1 Tokaanu Intertrip Scheme (Bus Splitting SPS)

If the 220 kV Tokaanu–Whakamaru–1 or 2 circuit trips, the Tokaanu 220 kV bus is automatically split. This reduces the loading on the remaining in-service Tokaanu–Whakamaru circuit by redistributing power flow from Bunnythorpe north to Auckland over all the 220 kV circuits connected at Bunnythorpe.

5.2.2 Edgecumbe–Owhata–2 Overload SPS

If the low capacity 110 kV Edgecumbe–Owhata–2 110 kV circuit overloads, it is automatically opened to remove the overload. This increases transmission capacity by transferring the load to the 220 kV system. However, there is not a great deal of spare 220 kV transmission capacity, so only a relatively small increase in generation in the Kawerau area (or decrease in load) is possible before a 220 kV transmission constraint occurs.

5.2.3 Bunnythorpe–Mataroa Overload SPS

The low capacity 110 kV Bunnythorpe–Mataroa–1 circuit constrains the capacity of the 220 kV system for power flow from Bunnythorpe north to Auckland. When the Bunnythorpe–

Mataroa–1 circuit overloads, an SPS to open the circuit would interrupt the through-flow and remove the overload on the circuit. This increases the transmission capacity on the 220 kV system.

This SPS is not implemented, but is modelled in the investigation to uncover the next generation constraint on the 220 kV system.

5.3 Methodology

DIgSILENT’s Power Factory Version 15.1.4 was used to calculate the network power flows.

UNI generation decommissioning: Waikato 110 kV issues

APPENDIX 5: Waikato 110 kV issues

March 2016

Keeping the energy flowing

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Executive summary

The purpose of this report is to present the impact of thermal generation decommissioning in the upper North Island on the Waikato 110 kV network. This report specifically focuses on the impact the generation decommissioning will have on the ability to close the Arapuni bus split in 2017.

The investigation illustrated we cannot proceed with our original intention to close the Arapuni 110 kV bus split. Therefore, this report is intended to inform industry of a change to our previously advised intention to close the Arapuni bus split. Retaining the Arapuni bus split beyond 2017 has impacts on the 110 kV network between Arapuni and Tarukenga. We will produce a separate report on options to address the impacts, including a net benefit test, for industry consultation for retaining the Arapuni bus split indefinitely.

The purpose of this investigation was to review the permanent closure of the Arapuni bus split from 2017, with all the proposed thermal generation decommissioning.

The thermal generators that are assumed unavailable in this analysis are:

- Otahuhu combined cycle (decommissioned)
- Southdown (decommissioned)
- Huntly Rankine units 3 and 4 (decommissioned)
- Huntly Rankine units 1 and 2 (planned decommissioning in December 2018)

The only significant generators remaining in the upper North Island are Huntly units 5 and 6, rated at 400 MW and 40 MW respectively (both are gas fired).

The investigation shows that if the Arapuni 110 kV bus split is closed in 2017, there is sufficient generation at Huntly to prevent post contingency (n-1) overloads on the 110 kV circuits between Tarukenga and Hamilton during summer peak load periods. However, by 2020, after the Huntly Rankine units are decommissioned (in December 2018), both the remaining Huntly generation and the Kinleith generation needs to be generating at rated capacity during summer peak load periods. Beyond 2020, there will be insufficient generation north of Hamilton even with maximum generation at Kinleith.

The operation of the grid becomes unacceptably constrained as the minimum generation requirements at Huntly and Kinleith (see Table 1-1) cannot be met. The worst case contingency is an outage on the 220 kV Hamilton–Whakamaru–1 circuit. This contingency causes the Arapuni–Hamilton–1 and 2 circuits to overload and the Arapuni runback scheme to reduce generation at Arapuni to a point where the Kinleith–Tarukenga–1 circuit overloads.

Table 1-1 shows the minimum generation required at Huntly in the summer peak load periods with various levels of Kinleith generation.

Table 1-1: Minimum Huntly generation required if Arapuni bus split is closed

Kinleith generation	Minimum Huntly generation [MW]			
	2017	2020	2025	2030
0 MW	570	620	840	1000
19 MW	485	525	655	790
39 MW	410	440	580	710

Even if the Huntly Rankine units are retained post 2018, it may not be possible to close the Arapuni bus split because the generation constraints north of Hamilton may still be prohibitive, especially when the Kinleith generation is not available.

In a more stringent n-G-1 scenario, there will be insufficient generation at Huntly beyond 2020 even if the Huntly Rankin units are retained. If the Kinleith generator is not generating then there will be insufficient generation at Huntly under an n-G-1 scenario as soon as the Arapuni bus split is closed in 2017.

1 Purpose of this document

The purpose of this report is to present the impact of proposed thermal generation retirements on our published intention to close the Arapuni 110 kV bus split from 2017.

2 Introduction

2.1 Purpose of the investigation

The relevant parts of the existing North Island 110 kV and 220 kV transmission network for this investigation is shown schematically in Figure 2-1.

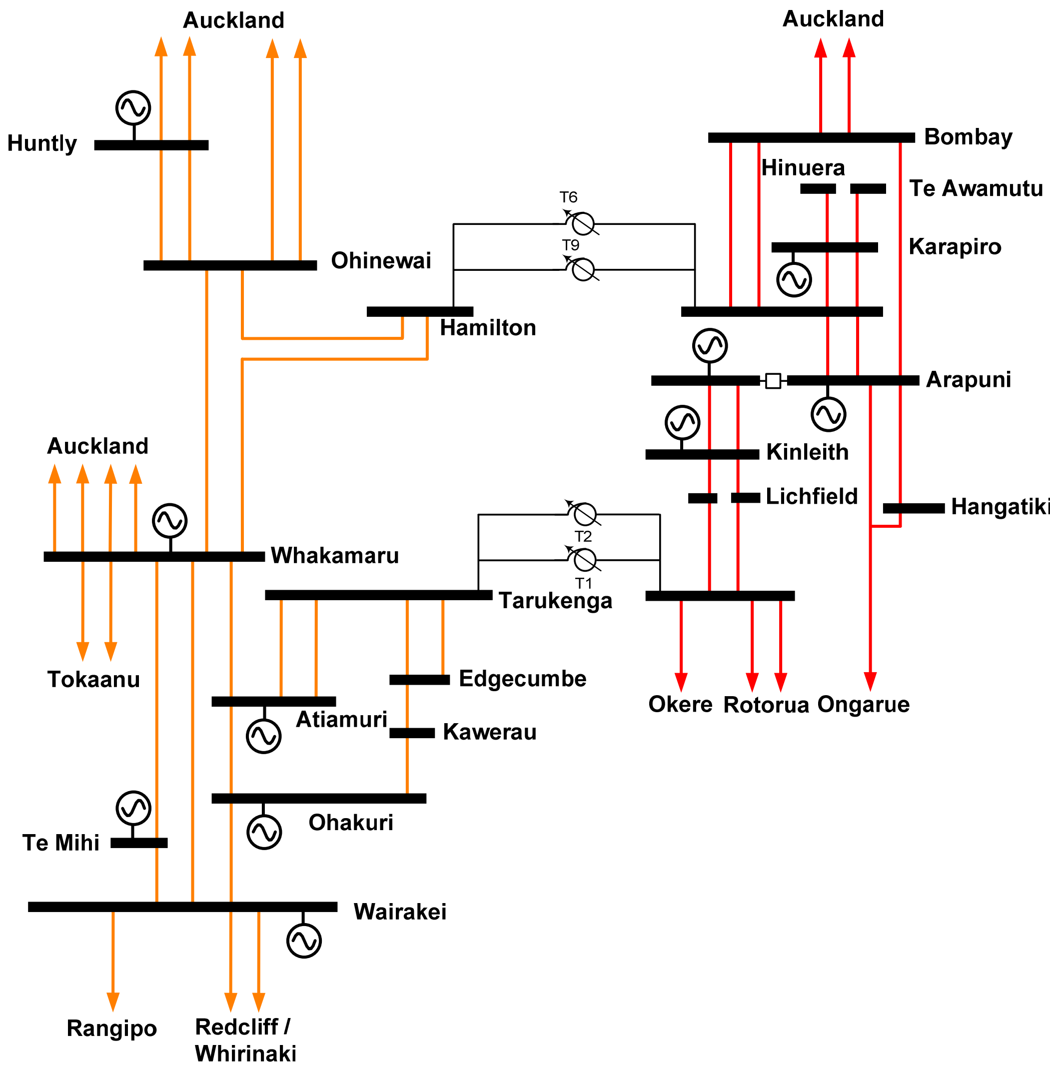

Figure 2-1: Schematic of existing 110 kV network between Hamilton and Tarukenga (normal operational configuration)

The Waikato 110 kV transmission network consists of mainly low capacity copper circuits between Tarukenga and Hamilton. The 110 kV network is also interconnected to the 220 kV network at Tarukenga and Hamilton. These interconnecting points effectively parallel the

220 kV and 110 kV networks between Whakamaru and Hamilton which creates interactions between the two networks.

Currently, the Waikato 110 kV network is split at the Arapuni 110 kV bus, creating:

- The north bus – which connects Arapuni generation to Hamilton, Bombay, Hangatiki, and the Central North Island
- The South bus – which connects Arapuni generation to Kinleith.

Arapuni G1-G4 are only configurable to the Arapuni north bus while G5-G8 can be configured to either the north or south bus.

We have previously indicated to the industry that we plan to close the Arapuni 110 kV bus split from 2017 to enable the connection of the Putaruru grid exit point.

The purpose of this investigation was to review the ability to close the Arapuni bus split from 2017 if all the thermal generators that are announced for closure by the end of 2018 are no longer available.

Table 2-1 lists the individual circuit ratings on the Waikato 110 kV network

Table 2-1: Details of 110 kV circuits between Tarukenga and Hamilton

Circuit	Conductor	Conductor Rating	
		Summer	Winter
Arapuni–Hamilton–1 and 2	Cu 19/2.34 @ 50^{o}C	51 MVA, 266 A	62 MVA, 325 A
Arapuni–Bombay–1	Cu 19/2.34 @ 50^{o}C	51 MVA, 266 A	62 MVA, 325 A
Arapuni–Kinleith–1	Cu 19/2.57 @ 50^{o}C	57 MVA, 300 A	70 MVA, 366 A
Arapuni–Kinleith–2	WolfGZ @ 50^{o}C	63 MVA, 333 A	77 MVA, 406 A
Kinleith–Lichfield–Tarukenga–1	Cu 19/2.34 @ 50^{o}C	51 MVA, 266 A	62 MVA, 325 A
Kinleith–Lichfield–Tarukenga–2	WolfGZ @ 50^{o}C	63 MVA, 333 A	77 MVA, 406 A

2.2 Scope of the investigation

The scope of this investigation was to investigate the minimum generation required north of Hamilton to allow the Arapuni 110 kV bus split to be closed from 2017.

This investigation did not include constraints on other areas of the transmission network as these are covered by separate studies.

3 Conclusion and Recommendations

3.1 Conclusions

The investigation shows that if the Arapuni 110 kV bus split is closed in 2017, prior to the Huntly Rankine units exiting the market, there is sufficient generation at Huntly to prevent post contingency (n-1) overloads on the 110 kV circuits between Tarukenga and Hamilton during summer peak load periods. However, the minimum generation requirements at Huntly are high, ranging from 410 MW if the Kinleith generator is at maximum capacity to 570 MW if the Kinleith generator is not generating.

By 2020, after the Huntly Rankine units are decommissioned in December 2018, both the remaining Huntly generation and the Kinleith generation needs to be generating at rated capacity during summer peak load periods. Beyond 2020, there will be insufficient generation north of Hamilton even with maximum generation at Kinleith.

Assuming the generation deficit needs to be made up at Huntly, the generation deficit north of Hamilton is a minimum of 140 MW by 2025 and 270 MW by 2030. There will be different levels of generation deficit if it is made up with new generation at other substations north of Hamilton. Table 3-1 shows the minimum generation required at Huntly in the summer peak load periods with various levels of Kinleith generation.

Table 3-1: Minimum Huntly generation required

Kinleith generation	Minimum Huntly generation [MW] (installed capacity at Huntly)			
	2017	2020	2025	2030
0 MW	570 (940)	620 (440)	840 (440)	1000 (440)
19 MW	485 (940)	525 (440)	655 (440)	790 (440)
39 MW	410 (940)	440 (440)	580 (440)	710 (440)

In a more stringent n-G-1 scenario, there will be insufficient generation at Huntly beyond 2020 even if the Huntly Rankin units are retained. If the Kinleith generator is not generating then there will be insufficient generation at Huntly under an n-G-1 scenario as soon as the Arapuni bus split is closed in 2017.

3.2 Recommendation

The recommendation is to retain the existing Arapuni bus split indefinitely[1]. With the Arapuni bus split open, localised issues in the South Waikato (between Arapuni and Tarukenga) can be managed in the short to medium term with special protection schemes. For the longer term, local transmission upgrades will be investigated, but will need to be economically justified before implementation.

As concluded in Section 3.1, there is insufficient generation north of Hamilton to allow the permanent closure of the Arapuni bus split in 2017. The operation of the grid becomes unacceptably constrained as the minimum generation requirements at Huntly and Kinleith (presented in Table 3-1) cannot be met. The worst case contingency is an outage on the 220 kV Hamilton–Whakamaru–1 circuit. This contingency causes the Arapuni–Hamilton–1 and 2 circuits to overload and the Arapuni runback scheme to reduce generation at Arapuni to a point where the Kinleith–Tarukenga–1 circuit overloads.

Even if the Huntly Rankine units are retained post 2018, it may not be possible to close the Arapuni bus split in the long term because of insufficient generation north of Hamilton, especially when the Kinleith generation is not available

[1] A net benefit test will be conducted to support the technical requirement to retain the Arapuni bus split.

4 Closing the 110 kV Arapuni bus split from 2017

In this analysis, the Waikato 110 kV network constraints are studied with Southdown, Otahuhu combined cycle, and all four Huntly Rankine units decommissioned.

The Waikato 110 kV network developments include:

1. A new grid exit point for Powerco (Putaruru) connecting on the Arapuni–Kinleith–2 circuit
2. A new Hangatiki–Te Awamutu 110 kV line (constructed by Waipa Networks) which is normally in-service.

The post 2018 North Island 110 kV grid is shown schematically in Figure 4-1.

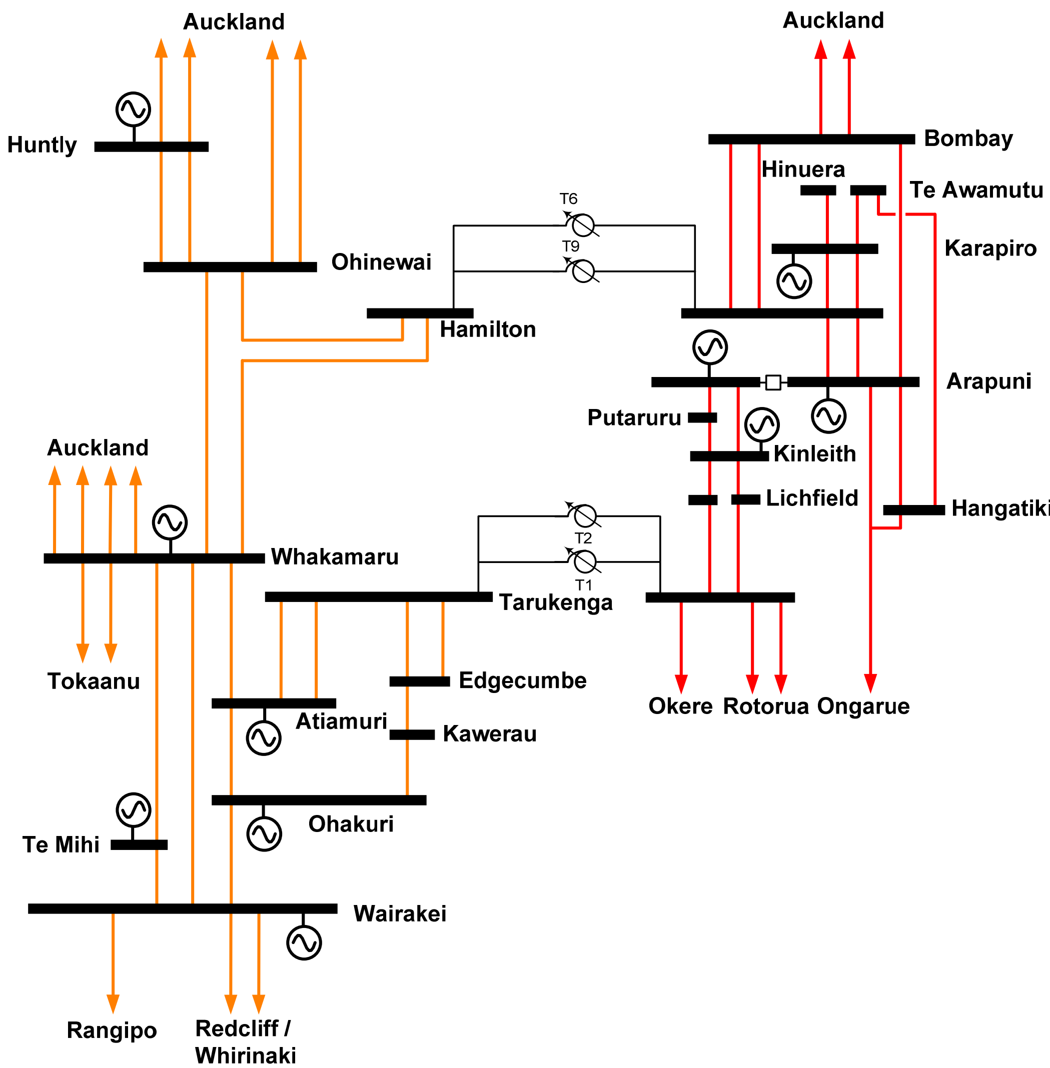

Figure 4-1: Proposed 2018 North Island 110 kV network configuration

The analysis assumes the 110 kV Arapuni bus split is permanently closed in 2017 to supply the new Putaruru grid exit point (deviation of the Arapuni–Kinleith–2 circuit).

With the Arapuni 110 kV bus split closed, generation in the following areas will need to be carefully controlled to prevent grid constraints.

1. Generation north of Hamilton needs to be high enough to prevent a contingency on the 220 kV Hamilton–Whakamaru–1 circuit causing the Arapuni runback scheme[2] to reduce Arapuni generation to a point where the Kinleith–Tarukenga–1 circuit overloads.
2. Generation at Arapuni and Kinleith needs to be high enough to prevent the loading on the Kinleith–Tarukenga–1 and 2 circuits from exceeding their n-1 capacities.

The two main factors that have the largest impact on generation requirements at Arapuni and north of Hamilton are:

1. availability of the embedded Kinleith generation
2. the 110 kV Hangatiki–Te Awamutu–1 circuit

4.1 Without Kinleith generation

Without the Kinleith generation, in:

- 2017, minimum generation of 570 MW is required north of Hamilton , and Arapuni generation must operate above about 185 MW
- 2020, minimum generation of 620 MW is required north of Hamilton, and Arapuni generation must operate at rated capacity
- 2025, minimum generation of 840 MW is required north of Hamilton, and Arapuni generation must operate at rated capacity
- 2030, minimum generation of 1000 MW is required north of Hamilton, and Arapuni generation must operate at rated capacity.

4.2 With Kinleith generation

With the Kinleith generation at 19 MW, in:

- 2017, minimum generation of 485 MW is required north of Hamilton, and Arapuni generation must operate above about 155 MW
- 2020, minimum generation of 525 MW is required north of Hamilton, and Arapuni generation must operate above about 170 MW
- 2025, minimum generation of 655 MW is required north of Hamilton, and Arapuni generation must operate above about 175 MW
- 2030, minimum generation of 790 MW is required north of Hamilton, and Arapuni generation must operate above about 180 MW (which is close to its installed capacity).

With the Kinleith generation at 39 MW, in:

- 2017, minimum generation of 410 MW is required north of Hamilton, and Arapuni generation must operate above about 125 MW
- 2020, minimum generation of 440 MW is required north of Hamilton, and Arapuni generation must operate above about 140 MW
- 2025, minimum generation of 580 MW is required north of Hamilton, and Arapuni generation must operate above about 145 MW
- 2030, minimum generation of 710 MW is required north of Hamilton, and Arapuni generation must operate above about 150 MW.

4.3 Hangatiki–Te Awamutu circuit open

The Hangatiki–Te Awamutu circuit, presently under construction, is expected to be normally in service. However, it will need to be opened to create a system split between Hangatiki and Te Awamutu for a number of outages, including outages of the Arapuni–Hangatiki and

[2] When the Arapuni runback scheme detects an overload on either of the Arapuni–Hamilton circuits, it will reduce the Arapuni generation until the Arapuni–Hamilton circuits are loaded to 95%.

Arapuni–Hangatiki–Ongarue circuits. If the Hangatiki–Te Awamutu–1 circuit is open, then in summer with 19 MW of generation at Kinleith, in:

- 2017, minimum generation of 595 MW is required north of Hamilton, and Arapuni generation must operate above about 140 MW
- 2020, minimum of generation 625 MW is required north of Hamilton, and Arapuni generation must operate above about 155 MW
- 2025, minimum generation of 755 MW is required north of Hamilton, and Arapuni generation must operate above about 160 MW
- 2030, minimum generation of 870 MW is required north of Hamilton, and Arapuni generation must operate above about 165 MW.

5 Assumptions

5.1 Demand Forecast

The analysis used the 2015 Transmission Planning Report North Island summer peak prudent demand forecast.

5.2 Generation Assumptions

The analysis assumed the following thermal generators are decommissioned.

1. Southdown generation
2. Otahuhu Combined Cycle
3. Huntly Rankine units (all four units decommissioned)

The analysis assumed the following dispatch of existing generation:

- Maximum geothermal and hydro generation in the Bay of Plenty, central North Island, and Hawkes Bay
- Maximum hydro generation at Karapiro
- Maximum thermal generation in the Taranaki region, included the proposed 100 MW Junction Road generating station
- Wind generation at 20% of installed capacity

5.3 Voltage Support assumptions

The analysis assumed the Huntly Combined Cycle (unit 5) is required to be in service for voltage support.

Voltage on the Arapuni 110 kV bus was set to 1.028 pu and the Kinleith generator is set to dispatch 2 Mvars when it is in service.

5.4 Grid planning assumptions

The analysis assumed that Waipa's Hangatiki–Te Awamutu 110 kV circuit is normally in service.

The HVDC was used as the slack bus.

5.5 Methodology

DIgSILENT's Power Factory Version 15.1.4 was used to calculate the network power flows and bus voltage

UNI Generation Decommissioning Report

APPENDIX 6: High voltage management

March 2016

Keeping the energy flowing

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Executive summary

1 Purpose

This report presents the outcome of an investigation into the management of high voltages in the upper North Island post-decommissioning of the last two Huntly Rankine units in 2018.

The decommissioning will leave Huntly Unit 5 as the only large generator in the Upper North Island. This investigation has been undertaken to determine the extent of high voltage management issues during light load periods, and whether an investigation into investment options may be justified.

The investigation was only intended to review historical operation and project this forward to predict grid operation and challenges post-decommissioning. Consideration of any capital investment options to resolve issues is not part of the scope.

2 Findings

Without the decommissioned generation available to absorb reactive power, it is likely that other actions will need to be taken. The usual action is switching out one or both 220 kV Pakuranga-Whakamaru circuits at light load times.

The scenario where only Huntly units 5 & 6 are available is not uncommon, and occurred approximately 44 times in the year to October 2015. This typically occurred at light load times, and often coincided with one or two circuits being switched out. It is apparent that this situation is manageable.

However, it seems likely that the system will need to operate without Unit 5 on occasion, both for normal maintenance and during forced outages. This generation pattern has not been observed in the last year, so the scenario was modelled using Transpower's DIgSILENT model to determine the effect on voltages. Modelling indicates that the scenario will be manageable, with additional circuits able to be switched out if required.

Previous investigations in 2013 determined that there was no case for an economic investment to manage the high voltage. However, with the generation decommissioning and records of operational history of the transmission grid since the NAaN and NIGU cables have been installed, there is good reason to review this outcome.

It is recommended that an investigation be undertaken into the economic benefit of capital investment. This is because the removal of circuits from service is likely to be frequent enough to have a significant cost, particularly in increased losses. This cost may be higher than the cost of investment to avoid the need for circuit switching.

1 Purpose of this document

The purpose of this report is to present the findings of an investigation into high voltage management in the Upper North Island.

The report summarises the high voltage management issue, describes how it is managed presently and the effects of the impending decommissioning of generation at Huntly. It reviews the previous decision not to invest capital in equipment to assist in management of high voltages.

2 Introduction

2.1 Background

In 2013 comprehensive investigations were undertaken by the System Operator and Grid Development, to determine the best approach to managing high voltages in the Upper and Lower North Island. A report on this work is available, titled "North Island Voltage Management Under Light Load Conditions" (October 2013).

From this work, procedures were developed to manage high voltages in a consistent way that met security requirements as well as market and industry rules and requirements. There is also a report titled

Since the NAaN cable was installed in 2014, the System Operator has regularly taken actions to manage high voltages at light load periods in the Upper North Island.

The most significant of these actions involves removing one or both 220 kV Pakuranga-Whakamaru circuits from service, typically between 9:30pm and 6:30am over the summer period. This occurred about 217 times in the year to October 2015.

2.2 Purpose of the investigation

This investigation was undertaken to determine the effect of the impending decommissioning of the remaining Huntly Rankine generation units, as well as the recent decommissioning of Otahuhu and Southdown generation.

Of interest is the potential requirement for further investment in order to manage high voltages post-decommissioning, and the need to extend the existing procedures to manage new low-generation scenarios.

2.3 Methodology

The investigation looked at the operation of the transmission grid over the year to October 2015. Data on the system voltages, generation dispatch, dynamic reactive plant (SVC and STATCOM) dispatch and circuit switching was analysed. This was compared to the System Operator plans and procedures in place for high voltage management. It was also compared to the results found in the 2013 investigation carried out by Grid Development and the System Operator.

Conclusions were drawn based on the expected change in generation dispatch during light load periods, following the Huntly decommissioning. It was assumed for the purpose of this investigation that the generation is replaced by increased HVDC injection at Haywards.

2.4 Scope of the investigation

The scope of this investigation was to determine the extent of the light load voltage management issues post-generation decommissioning. This included a review of recent voltage management actions, and the use of modelling to extend historical cases to a post-decommissioning scenario. It considered whether voltages could still be managed using existing procedures, once the generation has been decommissioned.

This investigation did not include finding potential solutions. It did not estimate the cost of the high voltage management measures presently taken or anticipated post-decommissioning.

3 Findings and conclusions

3.1 Previous study results

The 2013 study was driven by concern around the effect of the new HVDC Pole 3 on voltage, and the installation of the NAaN cables in Auckland with their inherent high capacitive contribution.

The assumptions made for that investigation included:

- Stratford, Otahuhu and Southdown generation out of service
- Huntly units 1 and 5 in service. All other Huntly generation out of service
- the NAaN cable in service
- the WRD 18 Mvar capacitor in service.

In the previous study, Huntly U5 was absorbing 133 Mvar, with U1 absorbing 22 Mvar. This suggests very little effect if the studies were repeated without U1 available.

The 2013 study concluded the following:

"*Various technical solutions for dealing with the increased voltage were investigated in this report. Studies showed that the most efficient and effective solution in the immediate term is to take AC lines out of service without the necessity for a GEN to be declared.*

The solution is, in effect, pre-emptive, as it is done before voltage runaway occurs and eliminates the capacitive effect of the lightly loaded AC lines. If the AC line to be switched off is selected appropriately, the security of the grid is not jeopardised.

However, taking an AC line out of service cannot be used as a single solution - it must be used in coordination with other mitigation measures such as operating HVDC in reduced voltage mode, operating in monopole, switching of AC filters according to rating rather than harmonic performance, changing Mvar set points and voltage set points."

Studies to assist the Coordinators in developing a voltage monitoring plan and identification of triggers resulted in the following document:

PR-DP-235_Manage Grid and Supply Voltage.pdf

This document outlines the procedures to manage high voltages in the upper and lower North Island.

3.1.1 Previous economic analysis

Previous economic analysis was based on the assumption that action would be taken if the upper North Island load fell below 830 MW (this was an average of historical data at the time). This was identified as the point at which the System Operator would begin to experience high voltage issues.

The 2013 year was analysed to understand the cost of losses due to the switching of circuits to manage high voltages. In summary:

- There were 940 half hours per year where load was below 830 MW
- The increased losses when switching a circuit out averaged 1.56 MW
- At a value of $80 per MWhr, annual losses are approximately $61k.

Capital investment was considered to be uneconomic.

3.2 Present situation

3.2.1 TPR summary

A light load scenario is studied as part of Transpower's Transmission Planning Report[1]. A summary from this report follows:

System condition 7: light load

This system condition represents a summer night light load period and is designed to highlight overvoltage issues. The specific assumptions include:

- North Island trough summer night load.
- Generation in the upper North Island is limited to one combined cycle generating unit at Huntly

Summary of transmission constraints

Possible transmission constraints include:

- Auckland area high voltages

The main concern during light load periods is high post-contingency voltages. These are dependent on load power factor and voltage profile across the North Island. The voltage profile can be maintained at around 1.0 pu at most generating stations. However, this requires generation to absorb a high level of reactive power pre-contingency, limiting the available response to a post-contingency event. It can also be difficult to change the system voltage to 1.0 pu during low load periods and change the voltage again to a higher voltage during normal and high load periods on a daily basis.

SC7: Auckland area high voltages

[1] See https://www.transpower.co.nz/sites/default/files/publications/resources/TPR2015Chapter6GridBackbone.pdf section 6.3.7.

Keeping the Auckland area voltages within acceptable limits with all circuits in service requires high levels of reactive power absorption from available units at Huntly. If this reactive power absorption is not available, circuits (such as Pakuranga–Whakamaru) may need to be removed from service to maintain voltages.

Possible solutions

At present, the high voltages are managed via operational measures (including removing circuits from service). If high voltages cannot be managed operationally then one transmission solution is to install shunt reactors. However, previous analysis showed capital expenditure to be uneconomic unless high voltages occur quite often. The frequency of high voltages will reduce over time as system demand at times of light load increases.

3.2.2 Existing management rules for the UNI voltage

The following document has been produced by the System Operator to assist the Operators in maintaining voltages within Code limits:

PR-DP-235_Manage Grid and Supply Voltage

This document summarises the actions to be taken pre-emptively as follows:

"If any one of ALB SVC, PEN STC or MDN STC's cannot be maintained at a level of less than 50% (-50 MVAR ALB, -30 MVAR PEN, -34 MVAR MDN STC 5&6 combined) of their rated import capability then examine options for switching out circuits.

If any one of ALB SVC, PEN STC or MDN STC's cannot be maintained at a level of less than 75% (-75 MVAR ALB, -45 MVAR PEN, -51 MVAR MDN STC 5&6 combined) of their rated import capability then switch out circuit(s)."

3.2.3 Change to economic assumptions

With the benefit of operational history with the NAaN and NIGU cables in service, assumptions around the frequency of line switching are found to have been too conservative.

The System Operator takes pre-emptive action, as it is not prudent to wait until voltages have started trending upwards. So while load was below 830 MW for approximately 500 hours per year, a circuit was taken out of service for the purpose of voltage management approximately 1800 hours per year.

This change in assumptions justifies further investigation into the economic benefits of capital investment for high voltage management.

3.3 Statistics from the year to October 2015

Post-decommissioning, the grid will be operating with only Huntly unit 5 in the upper North Island. Cases where this has occurred in the last year should indicate how the voltage will be managed post-decommissioning.

Data from Transpower's PI system was collated to create a picture of the way the grid is operated over low load periods.

The minimum UNI load reached while a circuit was out in the year to October was 687 MW. In this case both Pakuranga-Whakamaru circuits were out of service, Huntly units 4 and 5 are in service and all dynamic reactive support is in service except for Marsden STC6.

Statistics from the year to October 2015 include:

- Average UNI load just prior to switching out a circuit: 1210 MW (range: 844 MW to 1531 MW)

- average UNI load during the time a circuit is switched out: 937 MW (range: 687 MW to 1474)
- average minimum load each night that a circuit is switched out: 838 MW (range 687 MW to 979 MW)

In the last year there were no cases where only Huntly Unit 6 (40 MW) or no generation at all was on in the Upper North Island.

Some light load cases where Huntly Unit 5 was the only available significant generator in the Upper North Island are described in Table 3-1 below:

Table 3-1 Examples of grid operation when UNI region has only Huntly Unit 5 in service

Date	UNI min load	Dynamic support	PAK-WKM circuits	Notes
30 October 14	900 MW	MDN STC6 off	Both in service	
4 November 14	888 MW	MDN STC6 off	Both in service	
6 May 15	880 MW	All on	Both out of service	The second circuit was taken out after the last Rankine unit was turned off.
13 May 15	891 MW	MDN STC6 off	Both out of service	The second was taken out two hours after the last Rankine unit was turned off.
17 May 15	833 MW	MDN STC6 off	Both out of service	
22 May 15	866 MW	All on	Both out of service	

3.3.1 Drivers for switching out circuits

While the table shows cases where both circuits were taken out of service, in the majority of cases one circuit was out when only Huntly Unit 5 was on. These examples suggest that load and generator availability alone are not a good predictor of whether circuits will be taken out of service.

For almost all cases where Unit 5 was the only generator available, one circuit was already out of service and there was apparently no further action taken by the SO. On a handful of occasions the switching out of generation has coincided with removal of a second PAK-BHL-WKM circuit.

However, there does appear to be a correlation between the load and the number of circuits switched out:

Average minimum load while 1 circuit is switched out: 856 MW

Average minimum load while 2 circuits are switched out: 793 MW

There does not appear to be any significant relationship between the number of generators in service and the number of circuits switched out:

Average number of Upper North Island generation units in service when:

one Pakuranga-Whakamaru circuit in service: 1.8 units

neither Pakuranga-Whakamaru circuit in service: 1.6 units

The difference is small and can probably be accounted for by the typically lower load during the time that two circuits are off. I.e., the second circuit is not switched out because of fewer generation units being available.

What is the correlation between the SVC operating points and the switching out of circuits?

On average, just prior to a circuit being switched out the most highly loaded reactive equipment (at Albany, Marsden or Penrose) is operating at 53% of its limit. In practice this varied between 30 % and 100%. This is illustrated in Figure 3.1 below.

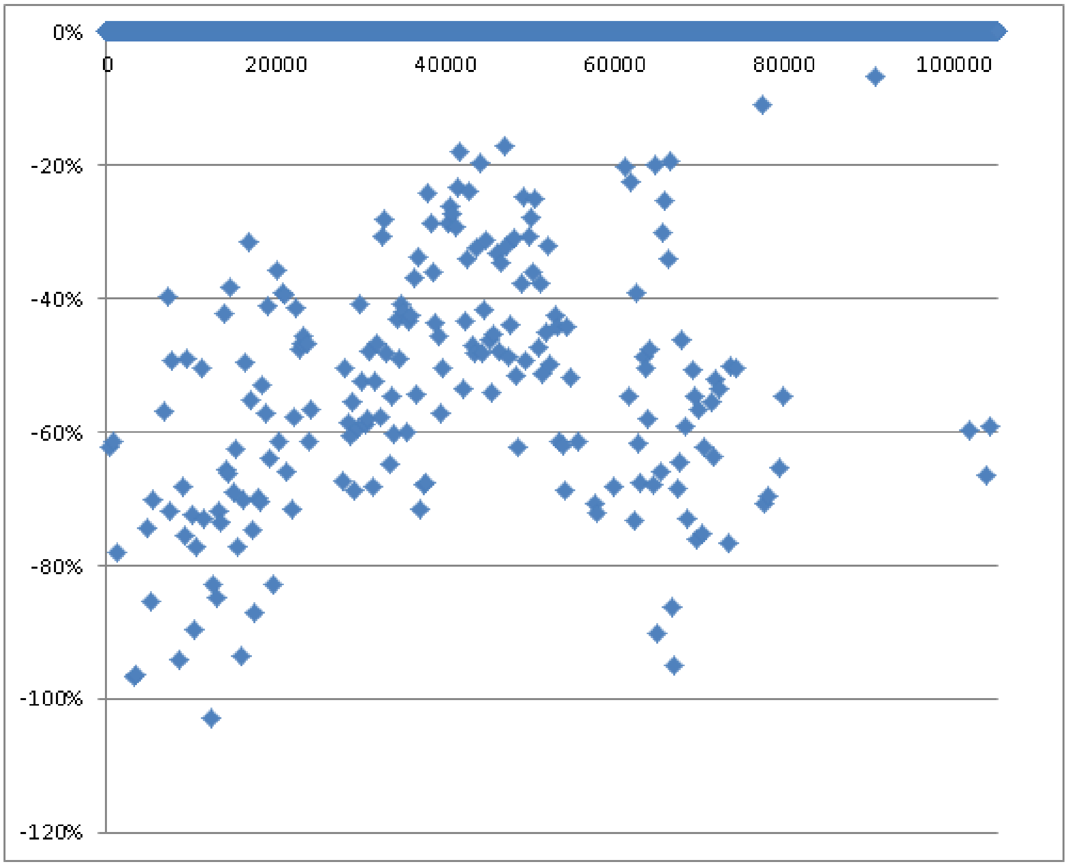

Figure 3.1 Illustration of the operating point of the most highly loaded SVC or STC in the Upper North Island, immediately prior to switching out a circuit

Table 3-2 shows the average reactive power absorption of dynamic support equipment in the Upper North Island for specific circuit configurations.

Table 3-2 Average operating point of UNI dynamic voltage control equipment

Case	MDN STC5 MVAR	MDN STC6 MVAR	PEN STC1 MVAR	ALB SVC MVAR
one PAK-WKM out of service	-4.7	-3.1	-24.3	-16.3
both PAK-WKM out of service	-3.9	-2.0	-24.9	-16.3
just before switching a circuit out	-4.1(12%)	-2.9(9%)	-31.6 (53%)	-29.4(29%)

Switching a circuit out appears to reduce the operating point of particularly the Albany SVC and to a lesser extent the Penrose STATCOM.

3.3.2 Huntly Unit 5 operation

Following the generation decommissioning, Huntly Unit 5 will be the only significant generator in the Upper North Island. It is not uncommon for this generator to be the only one in operation in the Upper North Island, and the graphs below (Figure 3.2 to Figure 3.4) show the load conditions, Mvar absorbed and SVC operating points when Huntly U5 is the only Upper North Island generator.

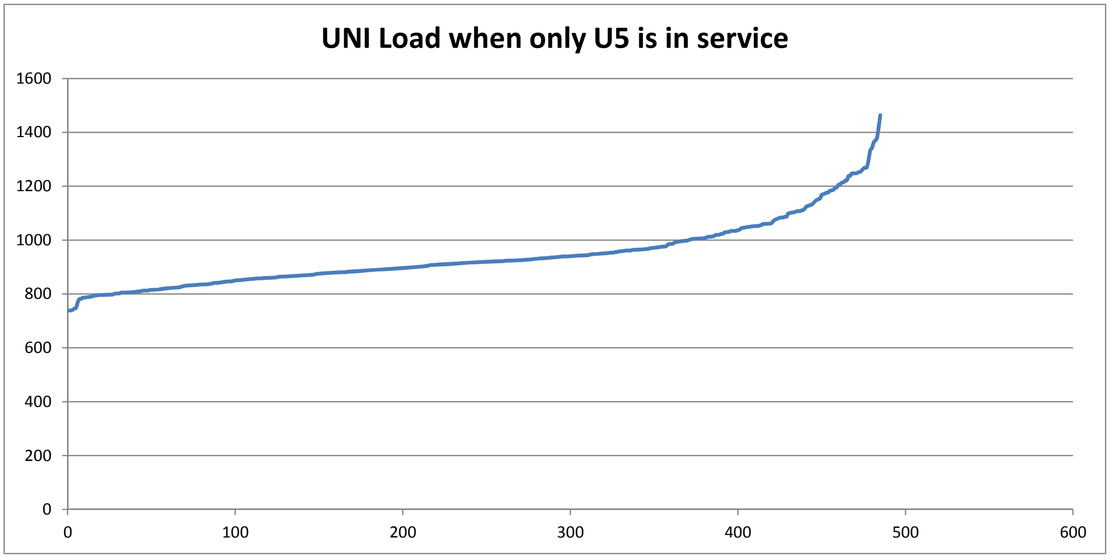

Figure 3.2 Load duration curve of UNI load when only Huntly Unit 5 is in service

Figure 3.2 indicates that unit 5 operating as the only Upper North Island generator is almost always at light load times, with the Upper North Island load between 800 MW and 1000 MW.

The graph in Figure 3.3 below shows that without the other units available, HLY U5 absorbs >100 Mvar most of the time.

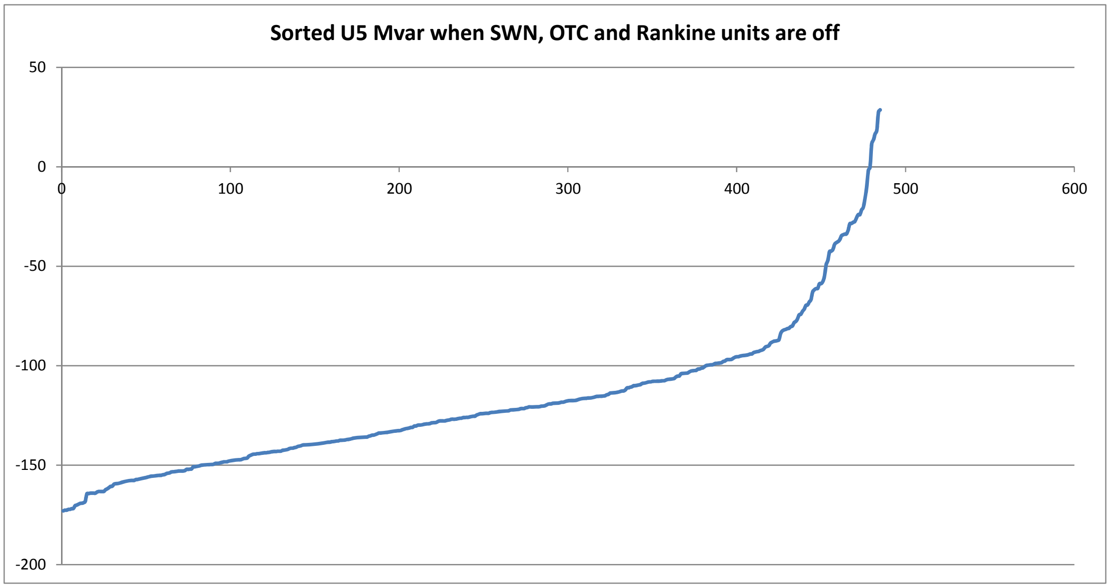

Figure 3.3 Huntly Unit 5 Mvar absorption when all other UNI generation is off

The graph in Figure 3.4 below shows the extreme scenario of all half-hour snapshots over the year to October 2015 where Huntly unit 5 was the only generator, and upper North Island load was less than 800 MW. Under this situation, one or both Pakuranga-Whakamaru circuits were out of service, and Unit 5 was often absorbing more than 100 Mvar at the same time as the combined SVCs and STATCOMs were absorbing 100 Mvar.

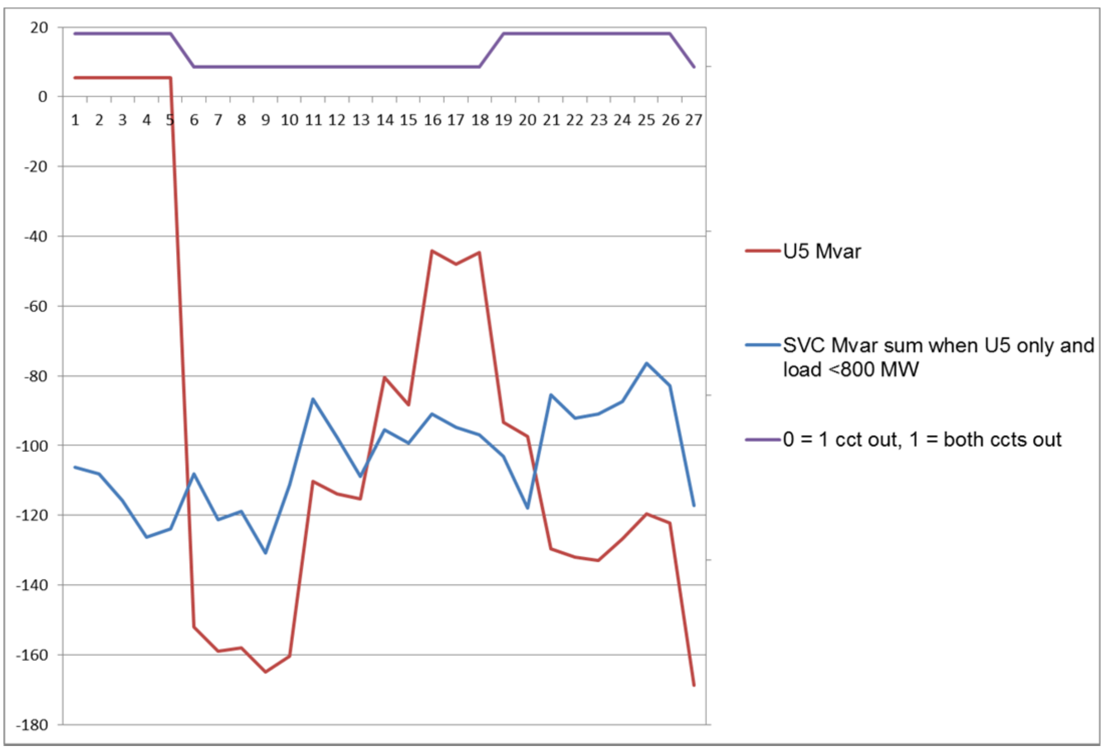

Figure 3.4 Unit 5 and dynamic plant operating points at light load periods

Two critical periods above are: 2 November 2014 4am (one circuit out)

1 January 2015 4am (both circuits out)

The minimum load over these periods was 786 MW and 741 MW respectively.

The lowest UNI load recorded over the year to October 2015 was 687 MW, on Christmas morning. In this case Huntly Unit 4 was also in service.

The duration curve for Mvar absorption while a Pakuranga-Whakamaru circuit is out of service is shown in Figure 3.5. The capability of dynamic voltage support equipment at Penrose, Albany and Marsden is:

Albany SVC 7:	+/- 100 Mvar
Marsden STC 5:	+ 40/- 34 Mvar
Marsden STC 6:	+ 40/- 34 Mvar
Penrose STC 1:	+/- 60 Mvar
Total:	**+ 240/- 228 Mvar**

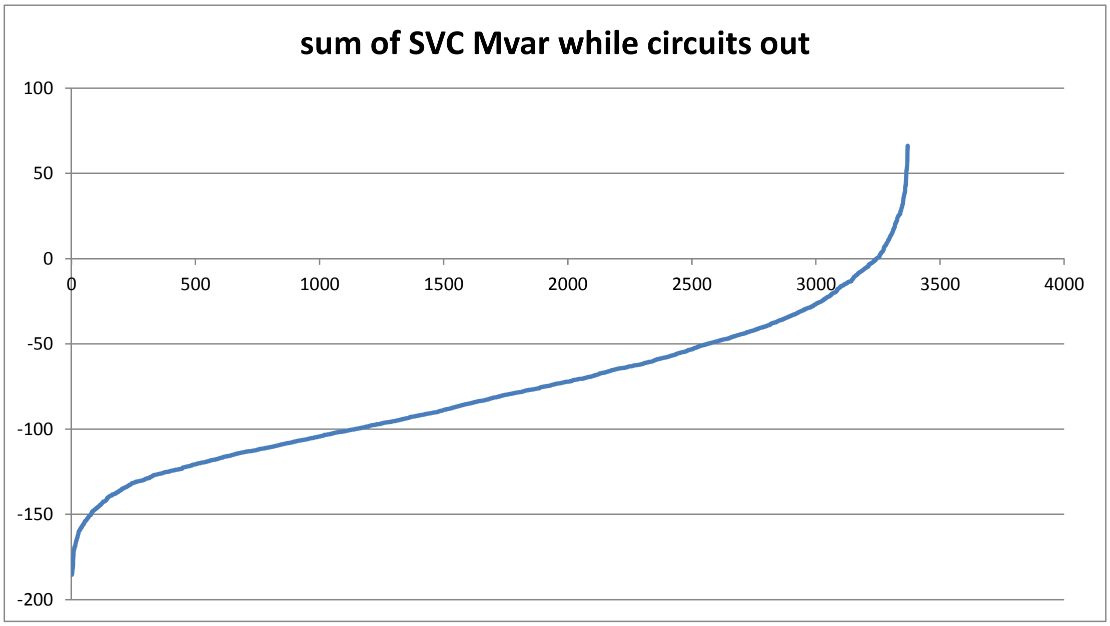

Figure 3.5 Upper North Island dynamic reactive equipment operating point duration curve, one Pakuranga-Whakamaru circuit out of service

3.4 Modelled post-decommissioning scenarios

Huntly Unit 5 cannot be expected to have 100% availability. Therefore, the system was tested by modelling three historic low load / high voltage scenarios but with Huntly Unit 5 not connected, to test the effectiveness of operator actions such as removing circuits from service.

Coordinators follow guidelines to manage high voltages, which state that if any one of Albany SVC, Penrose STC or Marsden STC's cannot be maintained at a level less than 75% of their rated capability, then switch out a circuit. This equates to:

Albany SVC 7:	- 75 Mvar
Marsden STC 5+6:	- 51 Mvar
Penrose STC 1:	- 45 Mvar

3.4.1 Pakuranga-Whakamaru 1 out of service without Huntly unit 5

The system was modelled to match the 2 November 2014 4am condition – the 220 kV Pakuranga-Whakamaru 1 was out of service. The upper North Island load was 786 MW. This included all four Huntly Rankine units out of service, and Southdown and Otahuhu generation out of service. The system operating points are shown in Table 3-3 below.

Table 3-3 Actual and modelled system operating points for 4am 2 Nov 2014

Location	Mvars (actual)	Bus voltages (actual)	Mvars (modelled)	Bus voltages (modelled)
Huntly U5	-173	220.6	-163	220.0
ALB SVC	-49.2	223.9	-48.1	223.1
PEN STC	-46.8	222.4	-43.6	222.6
MDN STC	-15.4	221.7	-13.0	220.9
Otahuhu220		222.3		222.7
Henderson220		224.2		224.0

The system was then remodelled with Huntly Unit 5 disconnected. The results are shown in Table 3-4 below. The amount of reactive power absorbed by the Albany SVC and the Penrose STATCOM exceed the criteria for the System Operator to take action to manage this light load scenario.

Table 3-4 With Huntly U5 and one Pakuranga–Whakamaru circuit out of service:

Location	Mvars (modelled)	Bus voltages (modelled)
Huntly U5		222.8
ALB SVC	-84.8	224.3
PEN STC	-50.6	224.0
MDN STC	-23.5	221.7
Otahuhu220		224.2
Henderson220		224.4

The system was again remodeled with the second Pakuranga–Whakamaru circuit taken out of service. The results are shown in Table 3-5 below. The amount of reactive power absorbed by the Albany SVC and Penrose STATCOM are low enough that no further action is required by the System Operator to manage this light load scenario.

Table 3-5 With Huntly U5 and two Pakuranga–Whakamaru circuits out of service:

Location	Mvars (modelled)	Bus voltages (modelled)
Huntly U5		222.7
ALB SVC	-44.8	223.1
PEN STC	-43.2	222.6
MDN STC	-13.1	220.9
Otahuhu220		222.7
Henderson220		224.2

Therefore, modelling suggests that this light load scenario with Huntly Unit 5 not connected is easily manageable by switching out the second Pakuranga–Whakamaru circuit.

3.4.2 Pakuranga-Whakamaru 1 & 2 out of service without Huntly Unit 5

The system was also modelled to match the 1 January 2015 4am condition – both 220 kV Pakuranga-Whakamaru 1 & 2 circuits were out of service. The upper North Island load was 741 MW. All four Huntly Rankine units were out of service, and Southdown and Otahuhu generation were out of service.

The system operating points are shown in Table 3-6 below.

Table 3-6 Actual and modelled system operating points for 4am 1 Jan 2015

Location	Actual system condition		Modelled system condition	
	Mvars	Bus voltages	Mvars	Bus voltages
Huntly U5	-121	222.2	-114	222.2
ALB SVC	-49	223.9	-36	223.9
PEN STC	-51	222.2	-49	222.9
MDN STC	-22	221.1	-24	221.1
Otahuhu220		222.6		222.9
Henderson220		224.3		224.2

The system was then remodelled with Huntly Unit 5 disconnected. The results are shown in Table 3-7 below. The amount of reactive power absorbed by the Penrose STATCOM exceed the criteria for the System Operator to take action to manage this light load scenario.

Table 3-7: Huntly U5 and two Pakuranga–Whakamaru circuits out of service

Location	Mvars (modelled)	Bus voltages (modelled)
Huntly U5		224.3
ALB SVC	-65	223.9
PEN STC	-51	223.3
MDN STC	-25	221.1
Otahuhu220		223.4
Henderson220		224.4

The system was again remodeled with additional switching, by removing the 220 kV Pakuranga–Penrose–3 cable circuit from service, and tapping the Penrose 220/33 kV supply transformers. The results are shown in Table 3-8. The amount of reactive power absorbed by the Penrose STATCOM is now low enough that no further action is required by the System Operator to manage this light load scenario.

Table 3-8: Huntly U5 out of service with additional switching

Location	Mvars (modelled)	Bus voltages (modelled)
Huntly U5		224.2
ALB SVC	-50	224
PEN STC	-30	223
MDN STC	-24	221.1
Otahuhu220		223.3
Henderson220		225.9

Therefore, modelling suggests that this light load scenario with Huntly Unit 5 not connected is easily manageable by also switching out the Pakuranga–Penrose–3 circuit and tapping the Penrose supply transformers.

3.4.3 Modelling operation at the lowest recorded load

The lowest recorded Upper North Island load over the year to October 2015 was 687 MW, at 4:30am 25 December 2014. Both 220 kV Pakuranga-Whakamaru 1 & 2 circuits were out of service. Huntly units 4 and 5 were in service.

The system was modelled with only Huntly Unit 6 in service. The results are shown in Table 3-10 below. The amount of reactive power absorbed by Albany SVC, Penrose STC and Marsden STC exceed the criteria for the System Operator to take action to manage this scenario.

Table 3-9 Huntly units 4 and 5 out of service

Location	Mvars (modelled)	Bus voltages (modelled)
Huntly U5		225.7
ALB SVC	-87.4	227.2
PEN STC	-71.6	225.1
MDN STC	-52.1	221.1
Otahuhu220		225.3
Henderson220		226.3

The system was then remodeled with the 220 kV Pakuranga-Penrose 3 circuit out of service. The results are shown in Table 3-10 below. The Albany SVC and Penrose STC reactive power absorption still exceeds the criteria for the System Operator to take action.

Table 3-10 Pakuranga-Penrose 3 out of service

Location	Mvars (modelled)	Bus voltages (modelled)
Huntly U5		224.9
ALB SVC	-86.9	226.5
PEN STC	-58.1	223.4
MDN STC	-46.2	221.1
Otahuhu220		224.2
Henderson220		225.4

The system was again remodeled with adjusted voltage set points to reduce reactive absorption to within 75% of limits. The results are shown in Table 3-11.

Table 3-11 Revised voltage set points at Albany and Penrose

Location	Mvars (modelled)	Bus voltages (modelled)
Huntly U5		226.0
ALB SVC	-75.6	228.1
PEN STC	-44.1	225.3
MDN STC	-49.6	222.2
Otahuhu220		225.7
Henderson220		227.0

The highest voltage is 1.037 pu, at Albany. This configuration just meets the requirements of limiting the STCs and SVC to 75% of their capacity. However, it would be prudent to have another circuit available to switch out if necessary.

4 Discussion of results

There have been a number of occasions when the power system has operated without the generation which is due for decommissioning. There is no indication from historical data that there were any issues managing this scenario.

In future, there will be an increased probability that the system will be required to operate with no generation on at Huntly, as well as the Auckland generation (following decommissioning of Otahuhu and Southdown). Huntly Unit 5 cannot be available 100% of the time.

The modelling indicates that, at least in situations that have arisen in the past, we can manage the system for a loss of Huntly Unit 5.

At present the document “PR-DP-235_Manage Grid and Supply Voltage” describes the options for switching out circuits such as Pakuranga-Whakamaru 1 & 2 and Pakuranga-Penrose 3. It would be prudent to have the option of a fourth circuit to switch out if necessary.

The historical data provides an indication of how often circuits are switched out to manage high voltages. The outage frequency may be high enough to justify investment in static reactive equipment, which would reduce the number of circuit outages required.

This will be considered at the next stage of investigation.

Security of Supply Analysis Findings and Implications of Thermal Decommissioning

December 2015

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IMPORTANT

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1. EXECUTIVE SUMMARY

This is the second in a series of reports by Transpower to help inform the electricity industry of the potential implications of thermal generation decommissioning. Transpower, in its role as the System Operator, has assessed security of supply in a series of 2019 scenarios which consider the closure, or potential closure, of North Island thermal generation – this includes removing up to 1040 MW of thermal generation.

The security of supply risk in 2019 is highly uncertain. The System Operator has assessed four scenarios that cover a range of security of supply risk outcomes. The purpose of the assessment is to help inform decision making by industry participants in response to the impacts of the closures.

There are three key issues that Transpower is investigating:

- Energy supply security – the ability of the power system to meet the demand for electricity in winter when inflows into hydro lakes are low.
- Peak load capacity – the ability to meet the peak demand for electricity in the North Island typically on a cold winter's evening.
- Operational limits of the power system – understanding the physical limits that determine how the power system is managed and what transmission and other core power system infrastructure investment is required.

This report covers the first two of these issues. The third issue is out of the scope of this analysis – it was the subject of the first report released in November 2015, and will be explored in further detail in early 2016.[1] Table 1 summarises the findings of this analysis.[2]

Table 1: Summary of security of supply risks

Scenario[3]	Energy supply security risk ('dry winter risk')	Peak load capacity risk
100 MW of new generation investment	**Very high**	**High**
350 MW of new or refurbished generation investment	**High**	**Moderate**
600 MW of new or refurbished generation investment	**Moderate to low**	**Low**
100 MW of new generation investment and Tiwai closure	**Low**	**High**

[1] See http://www.systemoperator.co.nz/activites/current-projects/impact-thermal-generator-decommissioning for more information.

[2] The risks quantified here are the risks of events such as scarcity pricing or an Official Conservation Campaign occurring rather than the risk of power outages.

[3] Assumes all Huntly Rankine units decommissioned along with Southdown and Otahuhu and a demand forecast of 1.38% year-on-year growth.

Modelling shows that, while the risk has been classified as high/moderate in the 350 MW scenario, security of supply risk is likely to be manageable in the 350 MW, 600 MW and Tiwai closure scenarios. Risk in the 350 MW scenario will be higher than that observed in recent history (2008 actual – 2016 forecast), but based on historical inflow sequences, it is unlikely that the power system will face an extended shortage of electricity supply.

It is the view of Transpower, in its capacity as System Operator, that the current energy markets in New Zealand operate well and will provide sufficient investment signals such that sufficient new or refurbished generation will likely be made available in 2019 as required. However, this situation will be monitored closely and further updates provided as part of regular security of supply assessments.

2. INTRODUCTION

Throughout 2015, there have been a series of events and announcements regarding closures of thermal generation plant in the North Island. Contact Energy decommissioned the 400 MW Otahuhu B power station on 30 September 2015, Mighty River Power announced the 140 MW Southdown power station will be decommissioned on 1 January 2016 and Genesis Energy announced the two remaining 250 MW Huntly Rankine units will be permanently withdrawn from the market by December 2018.[4]

The System Operator is obligated under Part 7 of the Electricity Industry Participation Code 2010 to provide information on all aspects of security of supply. The System Operator has used information currently available to complete a scenario analysis of security of supply over the next 4–5 years[5] in response to these decommissioning announcements.

Security of supply in this study has two elements. Energy supply security is the ability of the power system to ensure energy demand is met across the whole year, with a specific focus on ensuring energy supply during winter. Peak load capacity is the ability of the power system to meet any single instantaneous peak and therefore have sufficient capacity at any time to ensure supply can match demand.

To provide the basis for understanding, the System Operator has:

- identified a range of scenarios that cover a range of future outcomes
- analysed these scenarios to understand the effects of each scenario on the key security of supply metrics
- assessed the implications of each scenario studied including how each scenario influences another.

This report presents an initial analysis of the security of supply risks. The System Operator welcomes feedback on any of the assumptions and results contained in this report.

Useful information

Throughout this report, explanations of technical details, context and examples are presented in grey boxes.

[4] It should be noted that Genesis Energy have stated that the two remaining Huntly Rankine units will be decommissioned unless market conditions change significantly – this would imply that if market conditions changed such that it was justified to keep the units in the market they would not be decommissioned. See https://www.nzx.com/companies/GNE/announcements/268005 for more information.

[5] Further information on this work programme can be found here: http://www.systemoperator.co.nz/activites/current-projects/impact-thermal-generator-decommissioning.

3. SUMMARY OF SCENARIOS AND FINDINGS

The security of supply risk in 2019 is highly uncertain. With the recent announcements regarding decommissioning of thermal generation (in what is a highly renewable power system), the industry will need to plan carefully in the next 4–5 years to ensure security of supply is maintained at an acceptable level.

Security of supply risk in 2019 is extremely sensitive to changes in generation capacity and future demand. The effect of this uncertainty ranges from situations where system stress[6] can be easily managed to situations where system stress is likely to result in challenging conditions.[7]

It is possible that this uncertainty will impede potential mitigations (for example, new generation investment or demand-side initiatives). Therefore, it is important the security of supply risk associated with various future scenarios is well understood within the industry.

The System Operator will continue to communicate the security of supply risk to the industry and work with the industry to actively minimise future uncertainty.

Quantification of security of supply risk

Security of supply risk means different things to different participants. Consequently, it is difficult to describe the various levels of risk in a meaningful and consistent way.

In this report, the following descriptors have been used to quantify risk[8]:

Low risk: effectively no chance of an event occurring.

Moderate risk: approximately 0.1–1% chance of an event occurring.

High risk: approximately 1–5% chance of an event occurring.

Very high risk: approximately 5–20% chance of an event occurring.

Extreme risk: greater than 20% chance of an event occurring.

Note: An event is defined as an Official Conservation Campaign or scarcity pricing. (These terms are defined following section 3.1.).

[6] For energy supply security, this refers to dry hydrology conditions. For peak load capacity, this refers to the ability to manage situations where low generation (little wind, plant outages and so on) coincide with peak demand.

[7] Challenging conditions are conditions where the level of security of supply risk results in significant costs to the industry through actions such as an Official Conservation Campaign, scarcity pricing or a supply shortfall.

[8] Risks have been quantified in this way due to the consequence (which is one of the two factors of risk: likelihood and consequence) of these events being very high. For example an event with a low likelihood (0.1%), but a very high consequence, has been classified as a moderate risk.

3.1 DESCRIPTION OF SCENARIOS

The purpose of this report is to understand the impact of the two major sources of future uncertainty affecting the power system and therefore security of supply.

These sources of uncertainty are:

- investment in new or refurbished generation (likely to range between 100–600 MW)
- the future of the Tiwai aluminium smelter, which accounts for approximately 12–13% of total annual electricity consumption.

These sources of uncertainty have been analysed as they assess the most important factors that influence security of supply of which the industry has some ability to control.[9] The scenarios are:

- **100 MW of new generation**: This scenario assumes demand grows as forecast (average growth rate of 1.38% per annum[10]), thermal decommissioning proceeds as announced and 100 MW of new generation is commissioned (open-cycle gas generation in Taranaki). The purpose of this scenario is to understand the security of supply implications in 2019 if thermal decommissioning proceeds as announced and there is only minimal investment in generation.
- **350 MW of new or refurbished generation**: This scenario assumes demand grows as forecast, thermal decommissioning proceeds as announced and 350 MW of new or refurbished North Island (NI) generation is commissioned. This scenario uses the same assumptions as the 100 MW of new generation scenario with the addition of 250 MW of new or refurbished gas-fired generation assumed to be located at the Huntly node. The purpose of this scenario is to understand the security of supply implications in 2019 of two possible future scenarios where:
    - one of the two Huntly Rankine units is not decommissioned or
    - there is an additional 250 MW of new thermal generation investment.
- **600 MW of new or refurbished generation**: This scenario assumes demand grows as forecast, thermal decommissioning proceeds as announced and 600 MW of new or refurbished NI generation is commissioned. This scenario uses the same assumptions as the 100 MW of new generation scenario with the addition of 500 MW of new or refurbished generation assumed to be located at the Huntly node. The purpose of this scenario is to:
    - provide a counterfactual scenario representing the security of supply implications in 2019 with the two Huntly Rankine units remaining available or
    - provide a scenario where there is a large quantity of new or refurbished thermal generation (or some combination thereof).

[9] It is assumed in this analysis that electricity demand tends to only be elastic over the long term and therefore is not directly able to be controlled. As such, the impact of this source of uncertainty has not been assessed in this report. However, the Tiwai closure scenario is equivalent to demand growth of -0.52% when compared on the same basis as the base case demand growth (1.38%).

[10] This growth rate is the median growth rate from the Grid Development (Transpower) demand forecast adjusted to account for embedded generation. Detailed information on this forecast is available on request.

- **Tiwai closure prior to 2019**[11]: This scenario assumes demand grows as forecast, thermal decommissioning proceeds as announced, there is 100 MW of new NI generation investment and the Tiwai aluminium smelter closes. This scenario uses the same assumptions as the 100 MW of new generation scenario with the removal of 572 MW of demand in the lower South Island. The purpose of this scenario is to understand the security of supply implications in 2019 if thermal decommissioning proceeds as announced and Tiwai closes.

Impact of new generation that is not thermal generation

The scenarios described above assume all new generation is thermal generation. However, generation investment comes in many forms including geothermal, wind, hydro and solar. Like thermal generation, these alternative technologies all have the effect of improving security of supply (or lowering risk). Generally, all types of generation improve energy supply security in proportion to their long-term energy output or the amount of GWh/year they supply.[12] However, the contribution towards peak load capacity of new generation varies greatly depending on the technology. Predictable or discretionary technologies such as geothermal or hydro generation have a large effect on peak load capacity, whereas technologies that are unpredictable or do not generate over the peaks in demand such as wind or solar have a small effect on peak load capacity.

Impact of new generation that is not located in the upper North Island

The scenarios described above also assume new generation to be located either in the Taranaki region (≤ 100 MW) or at the Huntly grid injection point (> 100 MW). The location of any generation (new or existing) has an impact on the operational management of and investment decisions regarding the transmission network and power system. While detailed power system analysis is out of scope of this report, Transpower is investigating the implications of thermal decommissioning on operation of the power system and grid investment. More information on this work can be found here: http://www.systemoperator.co.nz/activites/current-projects/impact-thermal-generator-decommissioning.

3.2 100 MW OF NEW GENERATION SCENARIO

The scenario in which demand grows as forecast and thermal decommissioning proceeds as announced and with 100 MW of new generation investment results in a very high level of security of supply risk. The risk is likely to be higher than anything observed since 2000.

The System Operator expects, depending on outcomes in the market, moderate system stress (worst 5th–15th percentile of expected system conditions) will necessitate actions such as an Official Conservation Campaign (OCC) or scarcity pricing.

[11] Based on publically available information, Tiwai can exit their electricity supply contract with a year's notice from 1 January 2018 (by giving notice on 1 January 2017).

[12] There are some exceptions to this. Technologies that positively correlate with existing hydro inflows (ie. they amplify the natural volatility of hydro generation – new hydro generation is the best example of this) or technologies that negatively correlate with demand (for example, solar has its lowest output during winter, which is the period of highest demand in New Zealand).

In this scenario, the power system will have less ability to recover storage between years. The System Operator expects there will be a greater likelihood of an OCC and energy shortage in 2020 if hydrology in 2019 is poor.

See section 4.1 for energy supply security results of this scenario and section 4.2 for peak load capacity results.

Official Conservation Campaign (OCC)

An OCC is a public voluntary electricity savings campaign that is initiated at a pre-determined level of energy supply security risk (10% hydro risk, also known as the emergency zone). It is one of the main tools the System Operator has available to manage energy supply security. More information can be found in Part 9 of the Electricity Industry Participation Code 2010 (the Code).

Reserve deficit, energy deficit and scarcity pricing

Reserve and energy deficits arise when there is a shortage of instantaneous reserve or energy (ie. available generation) respectively. Typically, a reserve deficit will arise first as the cost of a reserve deficit is much lower than that of an energy deficit. A reserve deficit means the power system will be running at a reduced level of security. An energy deficit is a situation where load is required to be shed to match demand with supply.

Scarcity pricing is the market pricing mechanism used to ensure adequate pricing signals are maintained during an energy deficit, that is, times where supply is unable to meet demand. Scarcity pricing sets a price floor whenever load is disconnected to manage peak load capacity inadequacy. More information can be found in Part 13 of the Code.

3.3 350 MW OF NEW OR REFURBISHED GENERATION SCENARIO

The scenario in which demand grows as forecast and thermal decommissioning proceeds as announced and there is 350 MW of new or refurbished generation investment results in a high level of security of supply risk. The risk in this scenario is similar to that observed in the early 2000s.

The System Operator expects, depending on outcomes in the market, moderate system stress (worst 5^{th}–15^{th} percentile of expected system conditions) will not necessitate actions such as an OCC or scarcity pricing. However, if there is a high level of system stress (worst 1^{st}–5^{th} percentile of expected system conditions), the System Operator expects this situation will necessitate an OCC or scarcity pricing.

See section 5.1 for energy supply security results of this scenario and section 5.2 for peak load capacity results.

3.4 600 MW OF NEW OR REFURBISHED GENERATION SCENARIO

The scenario in which demand grows as forecast and thermal decommissioning proceeds as announced and there is 600 MW of new or refurbished generation investment results in a low to moderate level of security of supply risk. The risk in this scenario is similar to that observed in the mid to late 2000s.

The System Operator expects, depending on outcomes in the market, moderate levels of system stress (worst 1^{st}–5^{th} percentile of expected system conditions) will not necessitate actions such as an OCC or scarcity pricing.

See section 6.1 for energy supply security results of this scenario and section 6.2 for peak load capacity results.

3.5 Tiwai closure scenario

If the Tiwai smelter were to close (or the power system were to experience negative demand growth), energy supply security risk in 2019 will be low. With 100 MW of new generation investment, the System Operator expects energy supply security to be similar to that observed in 2013.

However, due to HVDC and lower South Island transmission limitations, analysis shows the power system will still be at increased risk of peak capacity shortage in the North Island even if the smelter closes. With minimal new generation investment, the NI peak load capacity risk will be the same as observed in the 100 MW of new generation scenario.

See section 7.1 for energy supply security results of this scenario and section 7.2 for peak load capacity results.

3.6 Notable implications of various scenarios

Tiwai closure uncertainty could influence investment decisions

The future of the Tiwai smelter (and, by extension, demand growth) could influence future investment in new generation – especially new generation that cannot respond to peak signals in the North Island.[13] The risk of Tiwai closure may affect investment decisions and therefore limit new generation developments.

See section 8.1 for more information.

The power system faces increased dependency on gas infrastructure

In the three generation scenarios (100, 350 and 600 MW scenarios), there is an increase in gas consumption ranging from 18–25 PJ above what is expected in 2016 (45 PJ). Increased gas consumption implies a greater dependency on gas infrastructure[14] for security of supply. An extended outage on the Maui pipeline could, for example, have significant ramifications for security of supply.

See section 8.2 for more information.

[13] As noted in section 3.5, a Tiwai closure has no impact on NI peak load capacity and therefore it is likely that the peak load capacity risk will be high even if Tiwai closes.

[14] Including supply and transmission infrastructure.

The power system faces increased dependency on HVDC transmission

High voltage direct current (HVDC) transmission link

The HVDC transmission link is a critical asset connecting the North Island and South Island electrically. The HVDC supports both energy supply security and peak load capacity. It allows South Island water to be conserved in dry conditions by allowing transfer of energy south as well as north to boost North Island peak load capacity. It was recently upgraded to provide greater transfer capacity across the link.

Following decommissioning of North Island thermal generation, the criticality of the HVDC, especially when transferring South Island capacity north, will increase.

The HVDC is likely to transfer, on average, higher levels of capacity north and do so more often. Due to the lack of North Island generation capacity, South Island generation will be essential to serving North Island demand. This differs from the present situation where South Island generation is typically dispatched to meet North Island demand on an economic basis.

See section 8.3 for more information.

Remaining thermal generation is expected to have increased capacity factors following the thermal decommissioning

In the scenario where 350 MW of new generation is built, the expected capacity factor of thermal generation (totalled across all thermal generation excluding Whirinaki) is 59% on average. For context, the capacity factor of thermal generation in 2014 (which had been slightly below average hydrology) was 38%. Therefore, remaining thermal generation in 2019 is not likely to experience the low capacity factors currently experienced by existing thermal generation.

See section 8.4 for more information.

4. Analysis of the scenario with 100 MW of new generation investment ('100 MW scenario') shows security of supply risk will be very high

4.1 Energy supply security risk in 2019 will be very high if demand grows as forecast, thermal decommissioning proceeds as announced and 100 MW of new generation is commissioned

Modelling results show that, if demand grows as forecast, thermal decommissioning proceeds as announced and only 100 MW of new generation is built, energy supply security risk will be very high. This is evidenced by:

- 1 out of 78 historical inflow sequences result in significant energy shortfall (355 GWh)
- the 2019 hydro risk curves (HRCs) are very high (May HRCs are 220–325% higher in 2019 than in 2016) and an Official Conservation Campaign (OCC) is likely in between 5–15% of inflow sequences.

Energy supply security modelling

The energy supply security has been quantified by detailed modelling of the power system in 2019 using two proprietary market models:

- SDDP (PSR Limited)[15]
- Emarket (Energylink Limited)[16]

This modelling makes a number of assumptions around what will happen at, or how the system will react to, periods of high system stress (for example during an Official Conservation Campaign or when storage approaches the bottom of the controlled[17] range). The System Operator has modelled demand response conservatively (capped at 2%) and has not modelled contingent storage. As such, the term energy shortfall represents a modelling outcome and should not be interpreted as predicting an energy shortage or power outages.

2016 Benchmarking

In this report, many of the metrics are benchmarked against the modelled outputs from 2016. The reason for doing this, rather than benchmarking against actual historical values, is to ensure the comparison is valid. A number of simplified or limited assumptions in the modelling may mean the outcomes, while as accurate as is feasible,

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[15] http://www.psr-inc.com/softwares-en/?current=p4028

[16] http://www.energylink.co.nz/

[17] There are two types of storage, controlled storage and contingent storage. Controlled storage is always available to be used for generation, contingent storage is only available during exceptional circumstances to help mitigate the risk of shortage.

do not exactly replicate reality. Consequently, the results have been benchmarked against 2016 where the assumptions are consistent across the two sets of results except for defined changes (for example, demand, available generation).

Accordingly, operation of the power system will be very different from what has been observed in the last 10 years. In addition to an increased risk of energy shortfall, there will be increased hydro spill (wasted energy), increased gas consumption and much greater reliance on the remaining thermal generators for energy supply security.[18]

The 100 MW scenario includes the following core assumptions:

- Demand growth averaging 1.38% per annum (p.a.) until 2019.
- 100 MW of new thermal generation.
- Median hydrology in 2018 and a Huntly decommissioning date of 1 January 2019 (to determine a start storage value).

4.1.1 1 out of 78 historical inflow sequences result in a high level (355 GWh) of energy shortfall in the 100 MW scenario

Figure 1 shows the storage trajectory in the 1932 sequence in the 100 MW scenario. The 1932 inflow sequence yields a storage trajectory that uses all available controlled storage.[19]

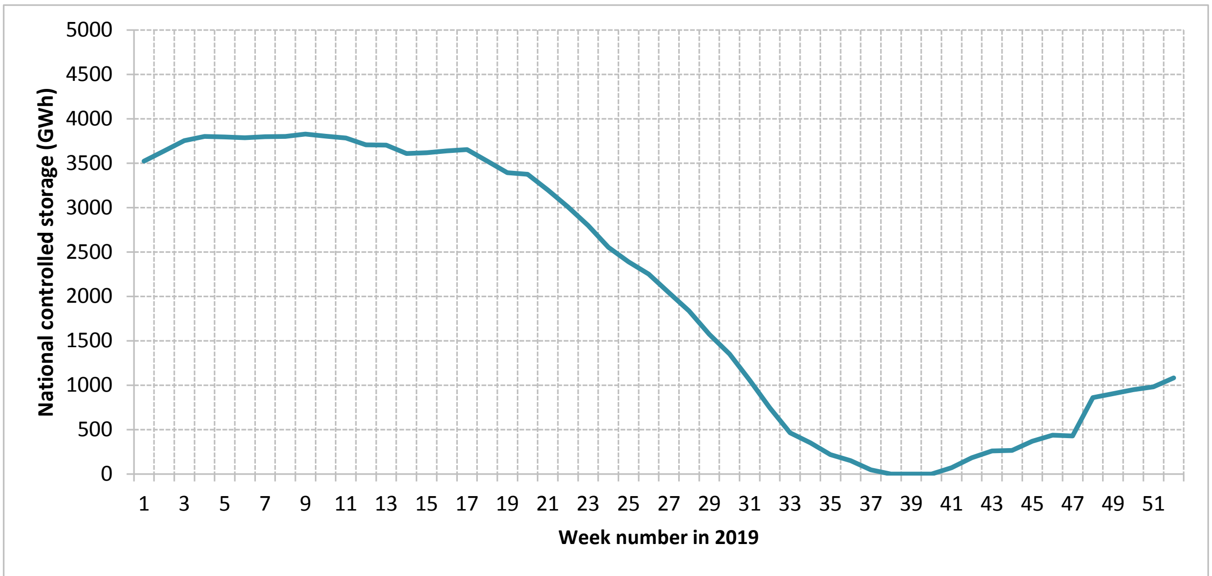

Figure 1: 1932 inflow sequence, 100 MW of new generation

The total energy shortfall observed in this inflow sequence is 355 GWh. No other sequences showed shortfall.

[18] Therefore, the consequences of critical contingencies, such as an unplanned outage at a major generator, will be far higher.

[19] The 1932 sequence is one of the worst inflow sequences on record.

4.1.2 An OCC is likely in between 5–15% of inflow sequences in the 100 MW scenario

Hydro risk curves (HRCs)

Hydro risk curves quantify the future risk of energy shortfall[20]. Current storage or future storage using simulated storage trajectories (see below) can be compared with the HRCs at any time, and an assertion about the current level of risk can be made.

For example, if the 10% HRC on 1 May is 2250 GWh:

- if current storage is 2700 GWh, the estimated risk of future energy shortfall would be less than 10%
- if current storage is 2250 GWh, the estimated risk of future energy shortfall would be exactly equal to 10%
- if current storage is 2000 GWh, the estimated risk of future energy shortfall would be greater than 10%.

Figure 2 shows the 2019 HRCs using the 100 MW scenario assumptions, with the 2016 HRCs shown for context.

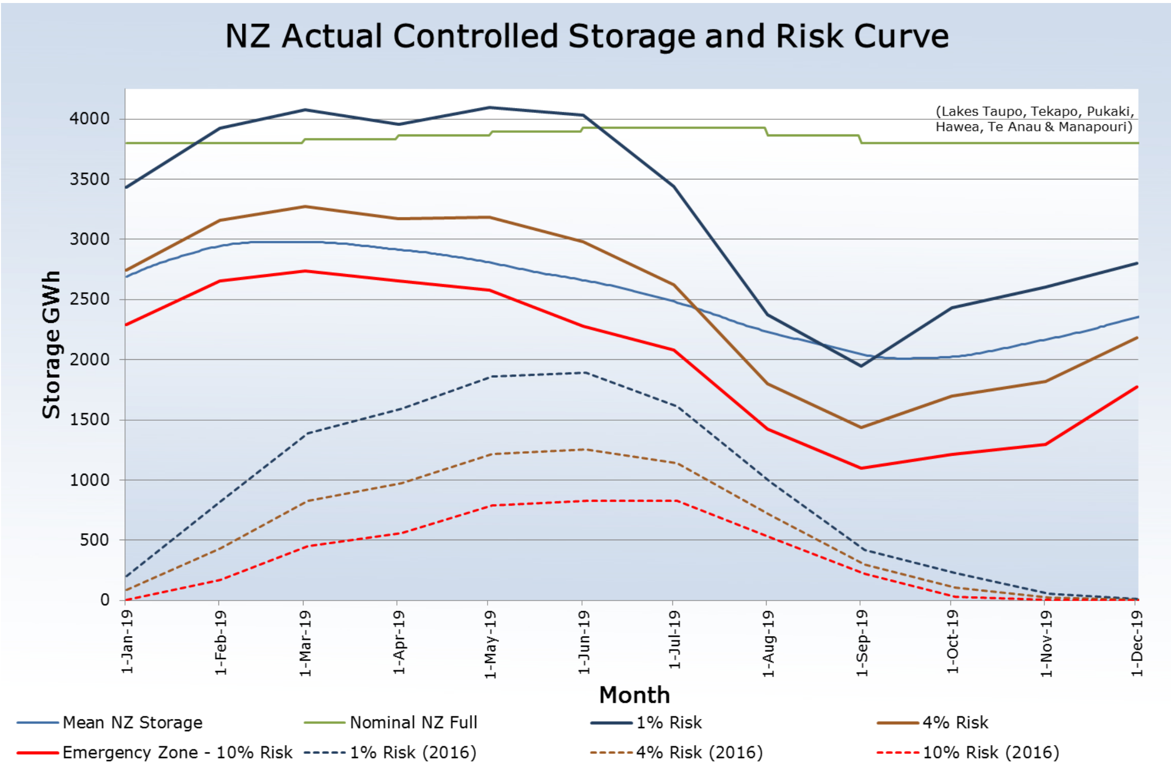

Figure 2: 2016 and 2019 hydro risk curves, 100 MW of new generation

[20] As discussed above, energy shortfall is a modelling outcome that does not consider contingent storage.

Simulated storage trajectories (SSTs)

Simulated storage trajectories are simulated outcomes of the power system across a year. Stochastic dual dynamic programming (SDDP) has been used to determine an optimal hydro-thermal management policy. This policy has then been used to produce a set of SSTs based on historical inflow sequences.

Figure 3 shows the SSTs for the 2019 year in the 100 MW scenario. In 15–20 out of 78 inflow sequences, the storage trajectory drops below the emergency zone, which is the trigger for an OCC. This would imply there is a 19–26% chance of an OCC in this scenario.

However, there are three considerations that will potentially reduce the likelihood of an OCC:

- Not all of these sequences drop into the emergency zone for a significant period (or by a significant amount).[21]
- Demand response[22] has only been modelled conservatively and may be underestimated (2% of demand response is bid at $500/MWh).[23]
- The modelling assumptions that underpin the SST results are inherently subjective and include assumptions around market behaviour and key factors (such as value of lost load) that have a high degree of uncertainty associated with them.

Therefore, an OCC is likely to be required in in the worst 5–15% of inflow sequences in this scenario.

[21] The System Operator may not initiate an OCC if it is determined that the OCC will only be required for a week or less.

[22] Demand response is the voluntary curtailment of demand in response to high prices. For example, assuming expected demand was 100 GWh, if prices exceeded $500/MWh, demand would reduce to 98 GWh.

[23] This means that demand will reduce by up to 2% at approximately $500/MWh.

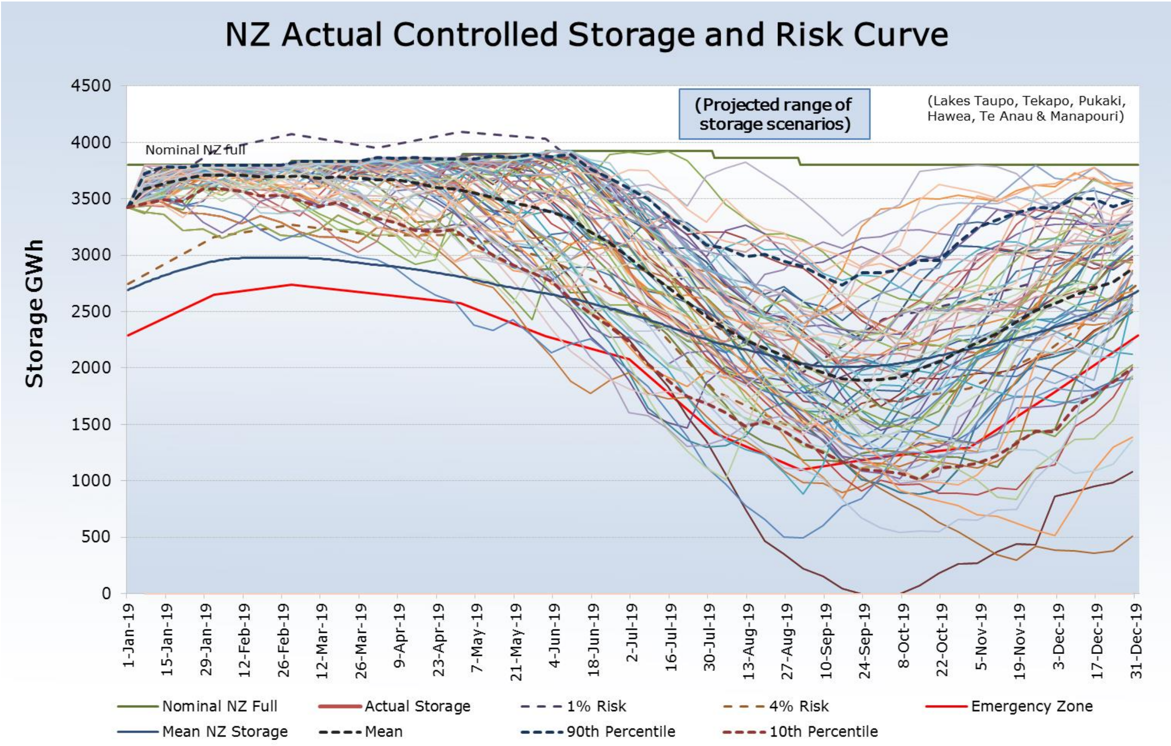

Figure 3: 2019 simulated storage trajectories, 100 MW of new generation

4.1.3 Operation of the power system is different in the 2019 100 MW scenario compared with today

Figure 4 shows an overall increase in expected thermal generation in 2019. This increase is predominantly due to the increase in demand between 2016 and 2019. However, as evidenced in Figure 5, the power system will be much more limited in its ability to mitigate dry year conditions. Thermal generation quickly reaches maximum output, and any further demand must be supplied by hydro generation (and therefore amplifies the stress caused by dry conditions).

This has the secondary effect of maintaining hydro storage at higher levels in summer and autumn (to mitigate the risk of a potential dry winter). This increases both thermal fuel consumption and hydro spill.

Expected thermal fuel consumption in 2019 in the 100 MW scenario is approximately 70 PJ (average across all inflows). This is an increase from 45 PJ in the 2016 scenario. Figure 7 shows the distribution of thermal fuel consumption across inflow sequences. For example in the 2019 100 MW scenario, 16 (out of 78) inflow sequences result in 65-70 PJ of thermal fuel consumption (compared to only 2 inflow sequences having this level of thermal fuel consumption in the 2016 scenario).

Expected hydro spill in the 2019 100 MW scenario is approximately 1323 GWh (average across all inflows). This is an increase from 882 GWh in the 2016 scenario, an increase of 50%.

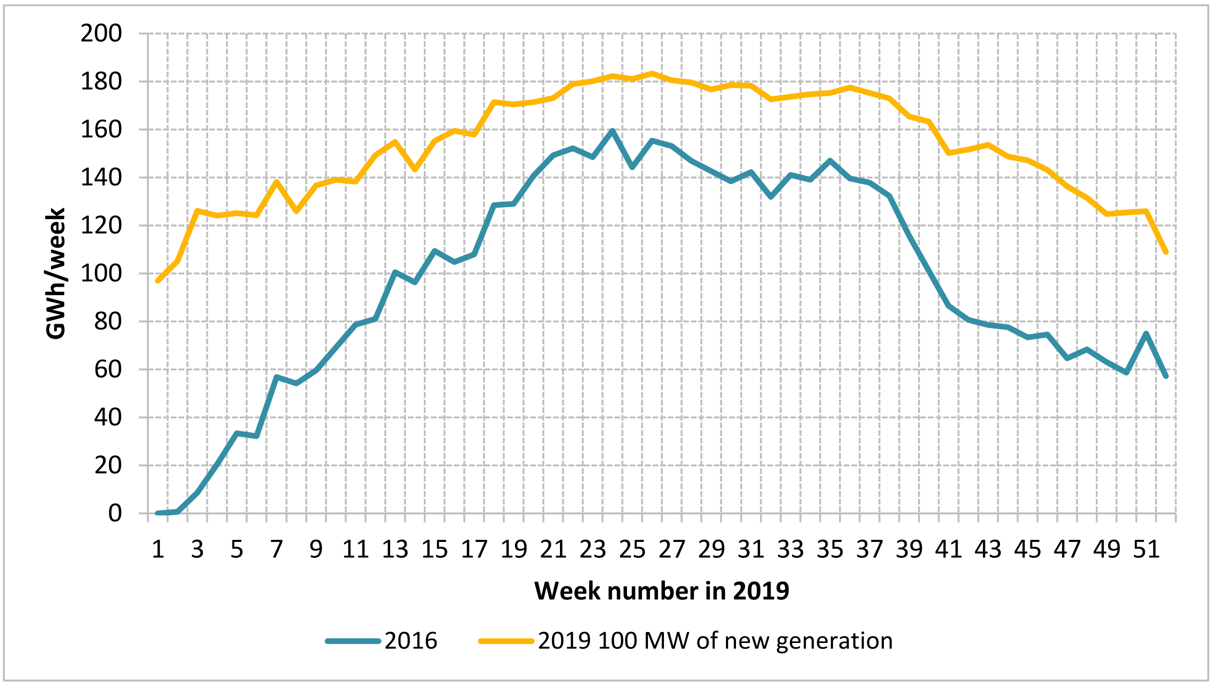

Figure 4: Mean thermal generation (across all inflows), 2016 scenario and 2019 100 MW scenario

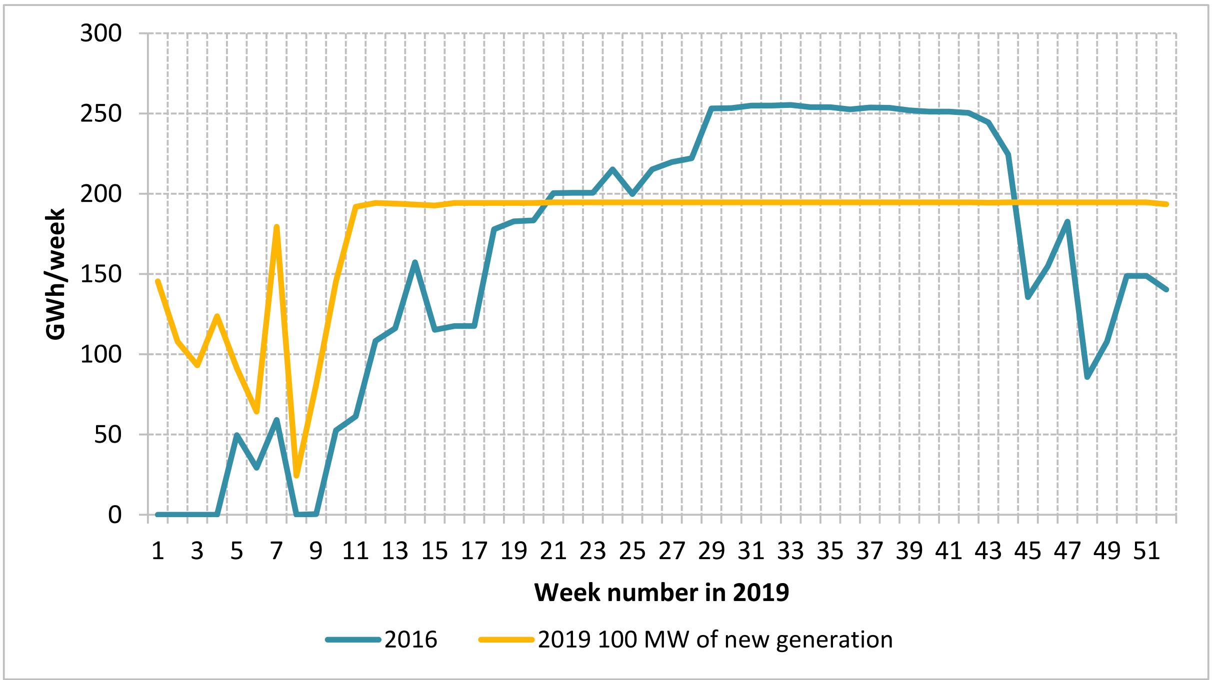

Figure 5: Thermal generation using the 1932 (dry year) inflow sequence, 2016 scenario and 2019 100 MW scenario

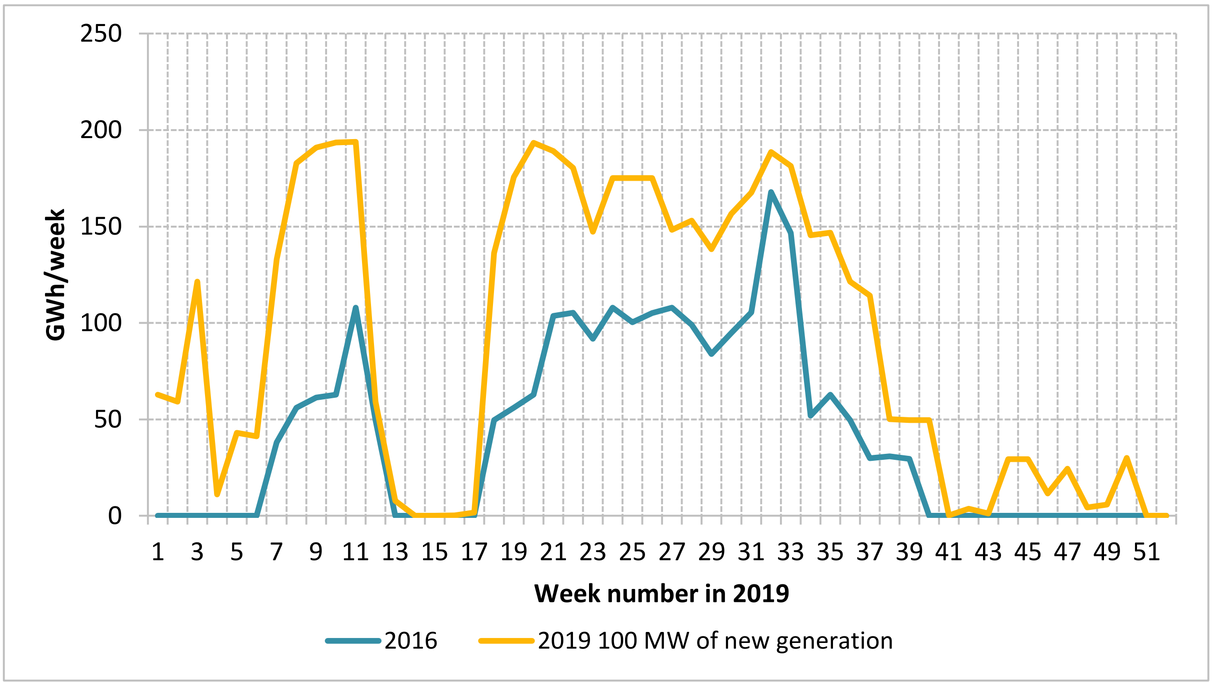

Figure 6: Thermal generation using the 1995 (wet year) inflow sequence, 2016 scenario and 2019 100 MW scenario

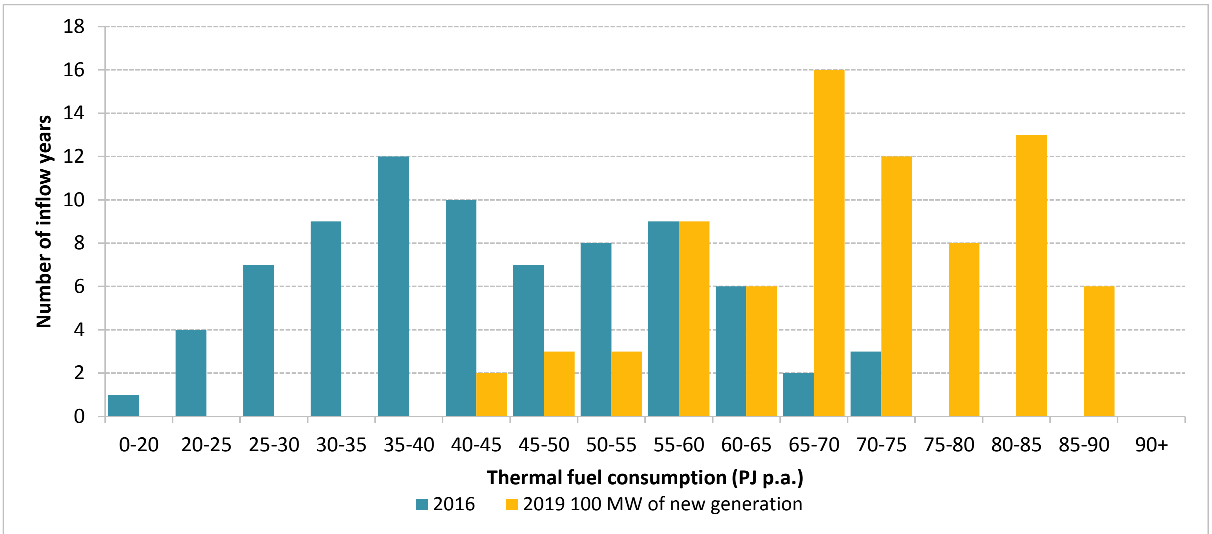

Figure 7: Thermal fuel consumption, 2016 scenario and 2019 100 MW scenario

Figure 8 shows the difference in operation of the most expensive thermal generator (not including Whirinaki).[24] In the 100 MW scenario, the capacity factor (total expected generation/theoretical maximum generation) of this plant is very high, implying the power system will have little redundancy available. This means that it is likely the power system may face a very high price level and be under significant amounts of system stress.[25]

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[24] Whirinaki generator is excluded from calculations because it has fuel supply limitations that distort its operation.

[25] There will be little availability for planned outages (maintenance) of infrastructure, and the negative effects of unplanned outages will be much larger.

Demand response results show a similar outcome. All scenarios have assumed 2% of demand response is dispatched at $500/MWh. In the 100 MW scenario, 870 hours of demand response was dispatched in 2019 on average (across all inflow years).

Conversely, in the 2016 scenario, 138 hours of demand response was dispatched on average.

Price modelling

In this analysis, the wholesale electricity market price is not modelled in a representative way. It is simply used as a means of determining a merit order for generation dispatch. No price forecasts have been explicitly made.

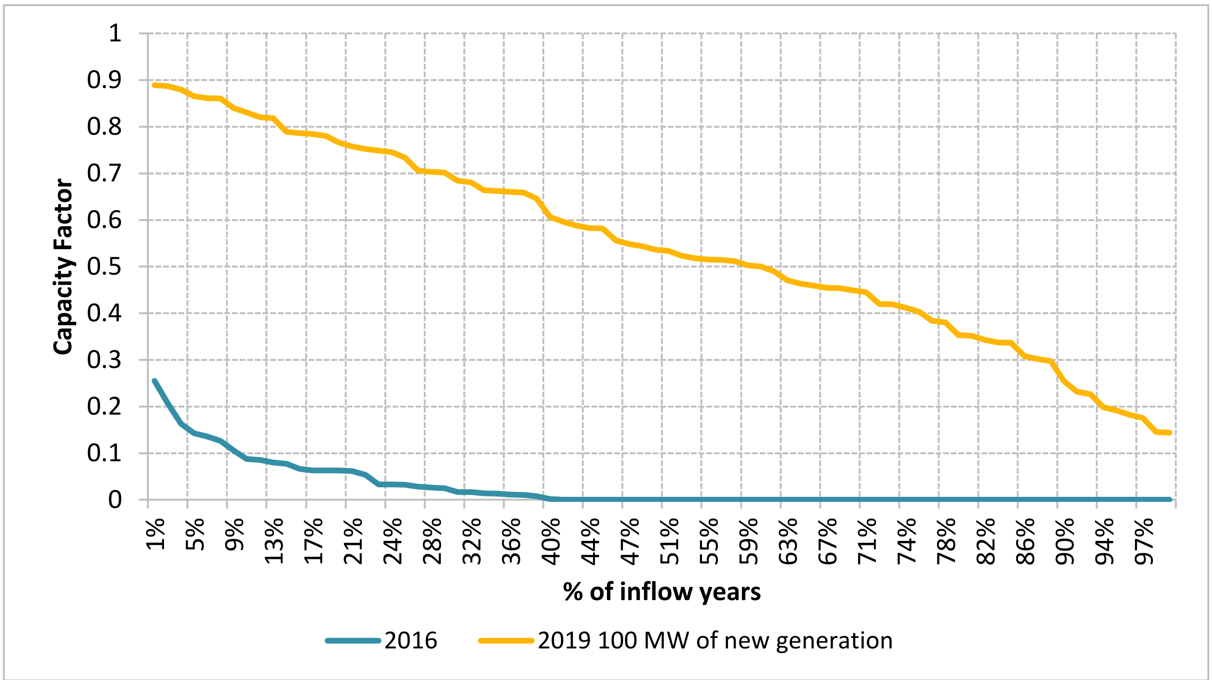

Figure 8: Capacity factor distribution (across inflow sequences) of most expensive thermal generator (excluding Whirinaki)

4.2 PEAK LOAD CAPACITY RISK IN 2019 WILL BE HIGH IF DEMAND GROWS AS FORECAST, THERMAL DECOMMISSIONING PROCEEDS AS ANNOUNCED AND 100 MW OF NEW GENERATION IS COMMISSIONED

If demand grows as forecast, thermal decommissioning proceeds as announced and only 100 MW of new generation is built, the modelling results show peak load capacity risk will be high. There is a very high likelihood (approximately 85–97%) the power system will experience a reserve deficit at some point during the winter and a moderate likelihood (approximately 2–3%) the power system will experience energy deficit and invoke scarcity pricing during the peak winter demand.[26]

[26] These results, and those in subsequent sections, assume that all generation will be offered into the market and available unless it is on a notified outage.

Figure 9 shows that, in the 100 MW scenario, peak load capacity risk in 2019 will be high. For context, the margin for reserves in the 2015 National Winter Group analysis was 748 MW and the capacity margin was 136 MW.[27]

National Winter Group methodology for peak load capacity analysis

The results in this section are based on the National Winter Group[28] method for reporting peak capacity. The charts show probability distributions of peak demand and peak supply in 2019. From the charts, it is possible to infer the ability of the power system to meet peak load based on the differences between peak demand and peak supply.

In this analysis, HVDC transfer is assumed at maximum north flow (1140 MW) and sets the reserve requirements in the North Island (total reserve requirement of 612 MW). Margins have been derived and shown on the charts for a situation of the 5th highest peak demand (P95) with the 10th lowest peak supply (P10). However, it is possible to derive a margin for any combination of peak demand and peak supply.

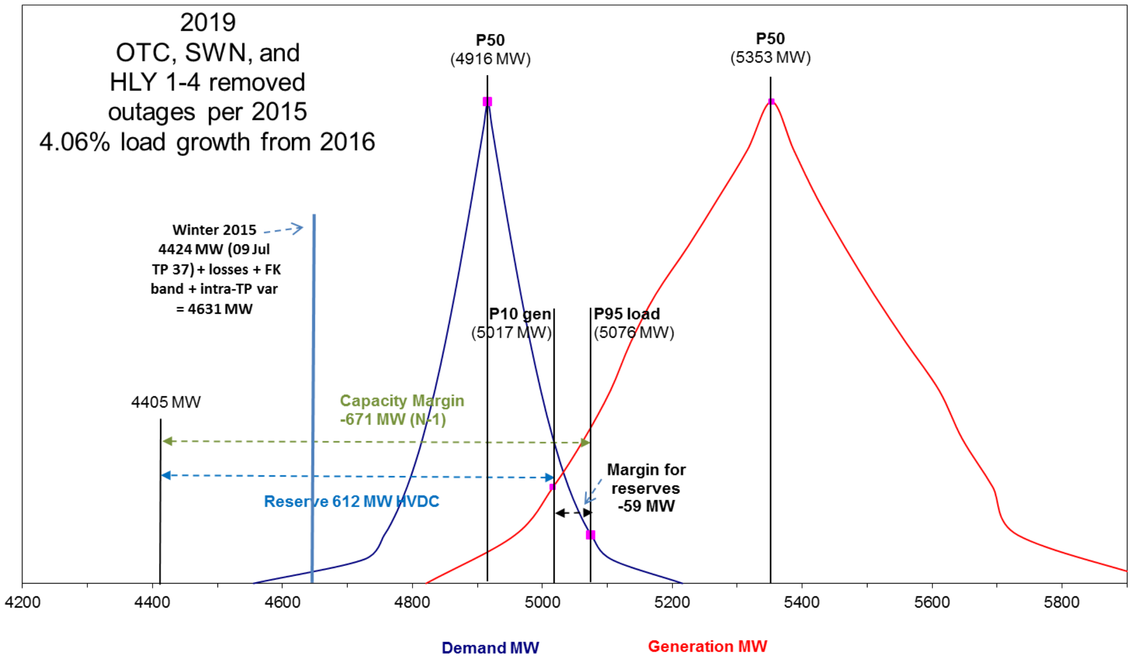

Figure 9: 2019 North Island peak capacity analysis, 100 MW of new generation

Using the data in Figure 9, it is possible to estimate the likelihood of an event, such as reserve deficit or scarcity pricing, occurring. The 100 MW scenario implies the following likelihoods:

- Likelihood of a reserve deficit occurring at least once during the winter: 85-97%.
- Likelihood of scarcity pricing being required (as a result of an energy deficit) at least once during the winter: 2-3%.

[27] Similarly, the first draft of the 2016 National Winter Group analysis is 531 MW and -81 MW for margin for reserves and capacity margin respectively.

[28] https://www.systemoperator.co.nz/engagement/industry-forums/national-winter-group

5. Analysis of the scenario with 350 MW of new or refurbished generation investment ('350 MW scenario') shows security of supply risk will be high

5.1 Energy supply security risk in 2019 will be high if demand grows as forecast, thermal decommissioning proceeds as announced and 350 MW of new generation is commissioned

Modelling results show that, if demand grows as forecast, thermal decommissioning proceeds as announced and 350 MW of new generation is built, energy supply security risk will be high.

The 2019 HRCs in this scenario remain high (the HRCs in May are 170–225% higher in 2019 than in 2016), and an OCC is likely in the worst 1–5% of inflow sequences.

Much like the 100 MW scenario, operation of the power system will be different from what has been observed in the last 10 years. When compared to the 100 MW scenario, hydro spill, gas consumption, thermal capacity factors and demand response are all lower, but overall, the operation is similar.

This scenario includes the following core assumptions:

- Demand growth averaging 1.38% p.a. until 2019.
- 350 MW of new or refurbished thermal generation.
- Median hydrology in 2018 and a Huntly decommissioning date of 1 January 2019 (to determine a start storage value).

5.1.1 An OCC is likely in between 1–5% of inflow sequences in the 350 MW scenario

Figure 10 shows the 2019 HRCs using the 350 MW scenario assumptions, with the 2016 HRCs shown for context.

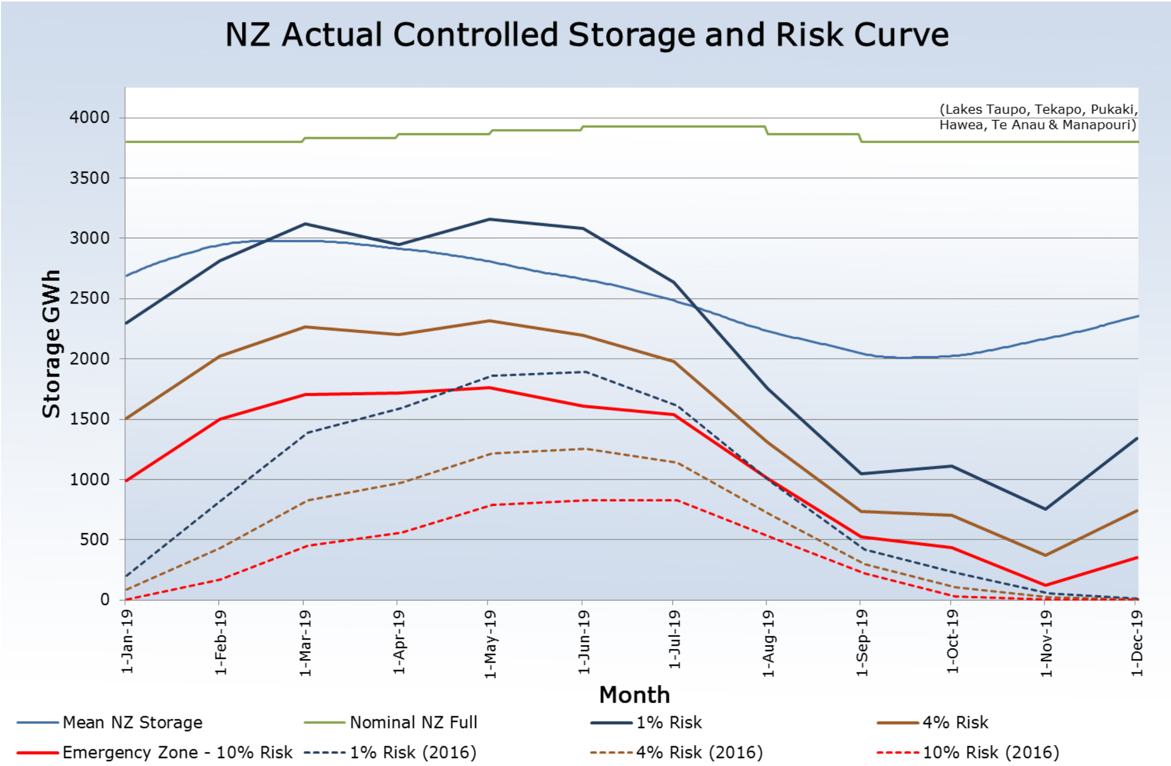

Figure 10: 2016 and 2019 hydro risk curves, 350 MW new generation

Figure 11 shows the SSTs for the 2019 year. In 1 out of 78 inflow sequences, the storage trajectory drops below the emergency zone, which is the trigger for an OCC. The System Operator expects an OCC will be required in 1–5% of inflow sequences.

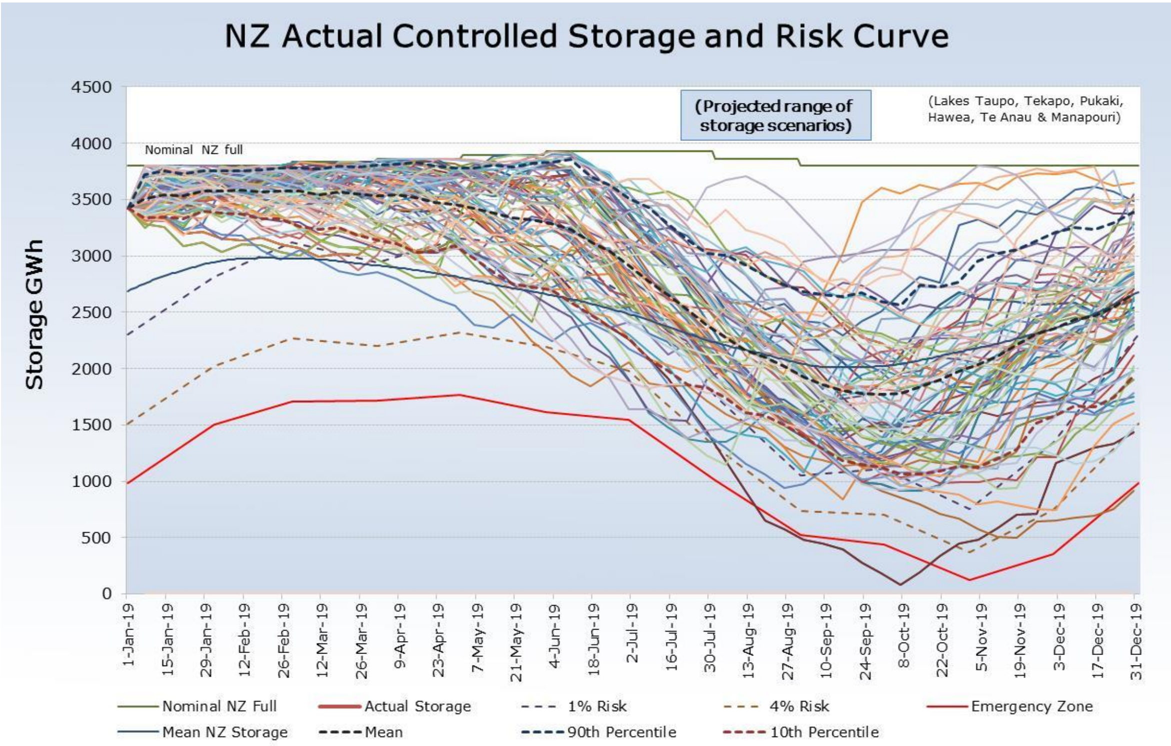

Figure 11: 2019 simulated storage trajectories, 350 MW new generation

5.1.2 Operation of the power system is different in the 2019 350 MW scenario compared with today

Figure 12 shows thermal generation in the 350 MW scenario to be similar to that observed in the 100 MW scenario. The System Operator expects hydro storage to be maintained at higher levels in summer and autumn to mitigate the risk of a potential dry winter.

Expected thermal fuel consumption in 2019 in the 350 MW scenario is approximately 66 PJ (average across all inflows). This is an increase from 45 PJ in the 2016 scenario. Figure 12, Figure 13 and Figure 14 show there is an increase in gas use effectiveness between the 100 MW scenario and the 350 MW scenario. In a dry sequence, more thermal fuel is used, and in a wet sequence, less thermal fuel is used.

Similarly, there is a significant reduction in spill in the 350 MW scenario compared to the 100 MW scenario. On average, spill is expected to be 1030 GWh in the 350 MW scenario compared to 1323 GWh in the 100 MW scenario. This spill is still higher than that expected in the 2016 scenario (882 GWh).

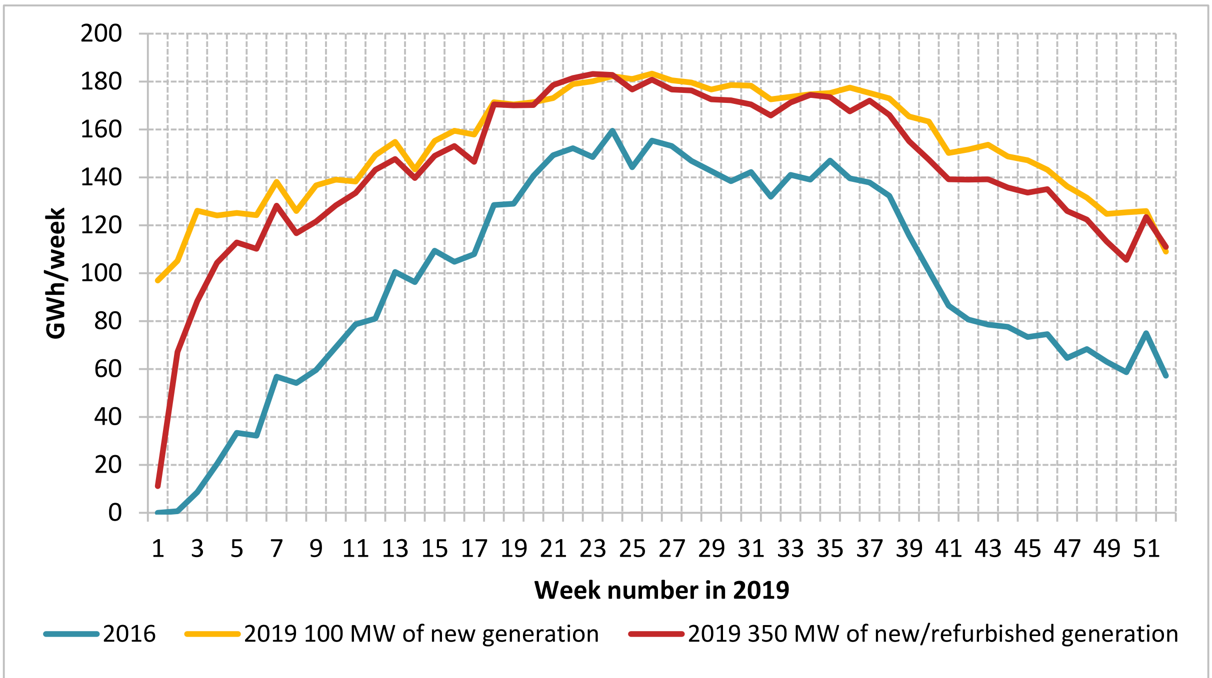

Figure 12: Mean thermal generation (across all inflows) in 2016 scenario, 2019 100 MW scenario and 2019 350 MW scenario

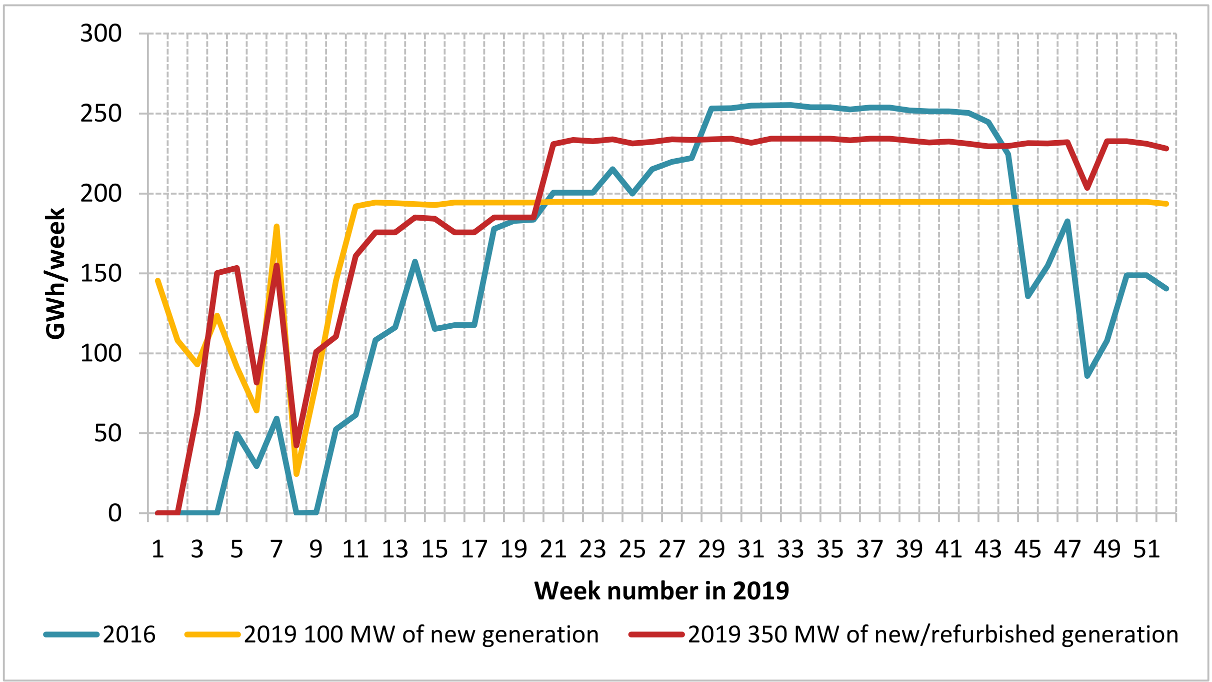

Figure 13: Thermal generation using the 1932 (dry year) inflow sequence in 2016 scenario, 2019 100 MW scenario and 2019 350 MW scenario

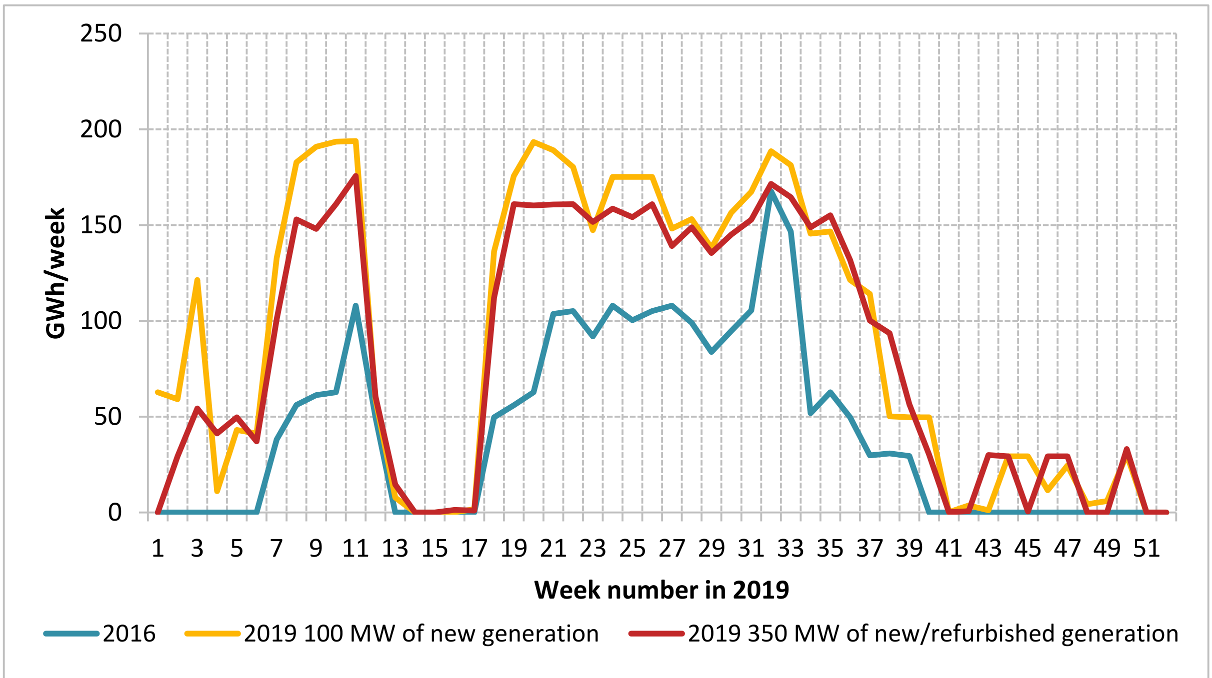

Figure 14: Thermal generation using the 1995 (wet year) inflow sequence in 2016 scenario, 2019 100 MW scenario and 2019 350 MW scenario

Figure 15 shows the difference in operation of the most expensive thermal generator (not including Whirinaki). There is a large difference between the 100 MW scenario and the 350 MW scenario.

The distribution of capacity factors implies an increase in redundancy in the power system (compared to the 100 MW scenario) and will mean that both price levels and system stress should be reduced.

A similar outcome is observed in the modelled demand response. In the 350 MW scenario, 243 hours of demand response was dispatched (averaged across all inflow years), compared to the 100 MW scenario of 870 hours. Demand response in this scenario is still higher than that expected in the 2016 scenario (138 hours).

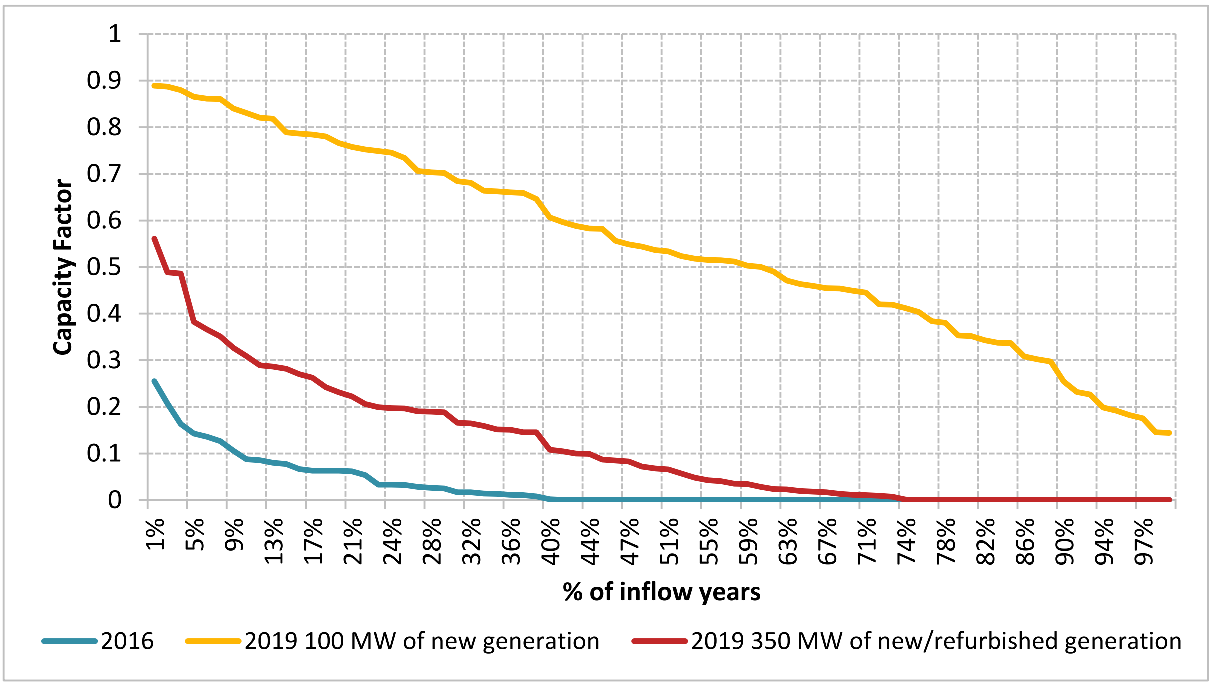

Figure 15: Capacity factor distribution (across inflow sequences) of most expensive thermal generator (excluding Whirinaki)

5.2 PEAK LOAD CAPACITY RISK IN 2019 WILL BE MODERATE IF DEMAND GROWS AS FORECAST, THERMAL DECOMMISSIONING PROCEEDS AS ANNOUNCED AND 350 MW OF NEW GENERATION IS COMMISSIONED

Modelling results show that, if demand grows as forecast, thermal decommissioning proceeds as announced and 350 MW of new generation is built, peak load capacity risk will be moderate. There is a moderate likelihood (approximately 10–20%) the power system will experience a reserve deficit at some point during the winter and a low likelihood (less than 1%) the power system will experience energy deficit and therefore require scarcity pricing during peak winter demand.

Figure 16 shows the 350 MW scenario peak load capacity risk in 2019. For context, the margin for reserves in the 2015 National Winter Group analysis was 748 MW and the capacity margin was 136 MW.[29]

[29] Similarly, the first draft of the 2016 National Winter Group analysis is 531 MW and -81 MW for margin for reserves and capacity margin respectively.

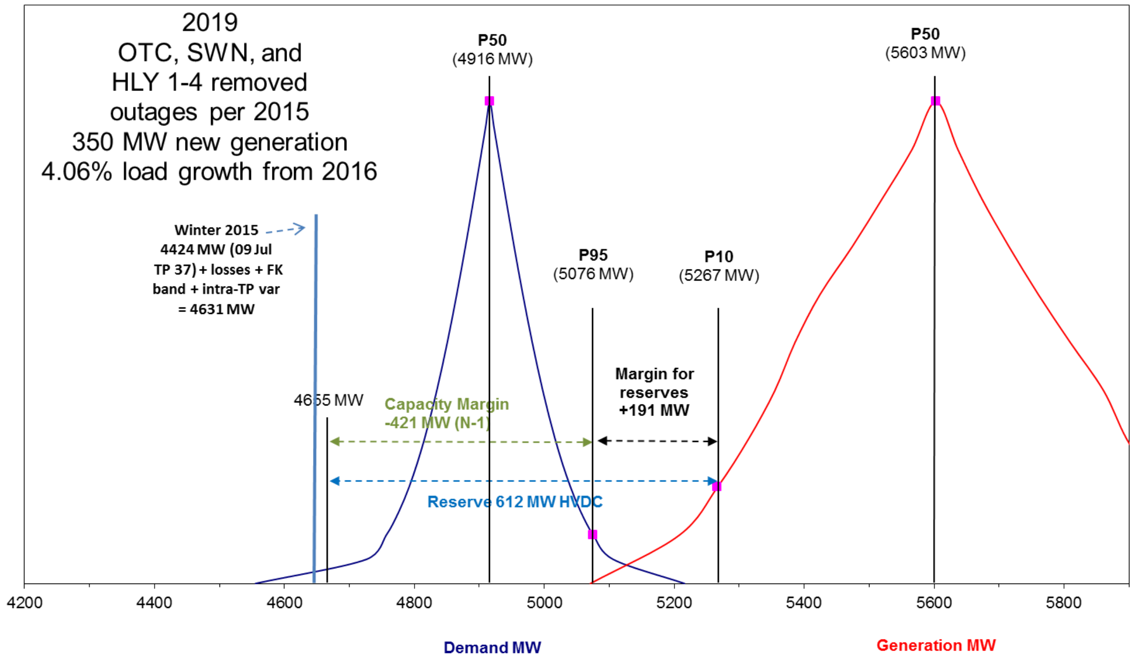

Figure 16: 2019 peak capacity analysis, 350 MW new generation

Using the data in Figure 16, it is possible to estimate the likelihood of an event, such as reserve deficit or scarcity pricing, occurring. The 350 MW scenario implies the following likelihoods:

- Likelihood of a reserve deficit occurring at least once during the winter: 10-20%.
- Likelihood of scarcity pricing being required (as a result of an energy deficit) at least once during the winter: 0.1-1%.

6. Analysis of the scenario with 600 MW of new or refurbished generation investment ('600 MW scenario') shows security of supply risk will be moderate to low

6.1 Energy supply security risk in 2019 will be moderate to low if demand grows as forecast, thermal decommissioning proceeds as announced and 600 MW of new or refurbished generation is commissioned

Modelling results show that, if demand grows as forecast, thermal decommissioning proceeds as announced and 600 MW of new generation is built, energy supply security risk will be low to moderate.

The 2019 HRCs in this scenario are higher than those derived for 2016 (May HRCs are 135–165% of 2016 values), and an OCC is unlikely to be required based on historical inflow sequences. However in 2–3 inflow sequences, New Zealand storage approaches, and only narrowly avoids, the trigger for an OCC (10% HRC). Therefore, the System Operator has classified this scenario as moderate to low risk rather than low risk.

This scenario includes the following core assumptions:

- Demand growth averaging 1.38% p.a. until 2019.
- 600 MW of new or refurbished thermal generation.
- Median hydrology in 2018 and a known Huntly decommissioning date of 1 January 2019 (to determine a start storage value).

6.1.1 An OCC is not likely in the 600 MW scenario

Figure 17 shows the 2019 HRCs using the 600 MW scenario assumptions, with the 2016 HRCs shown for context.

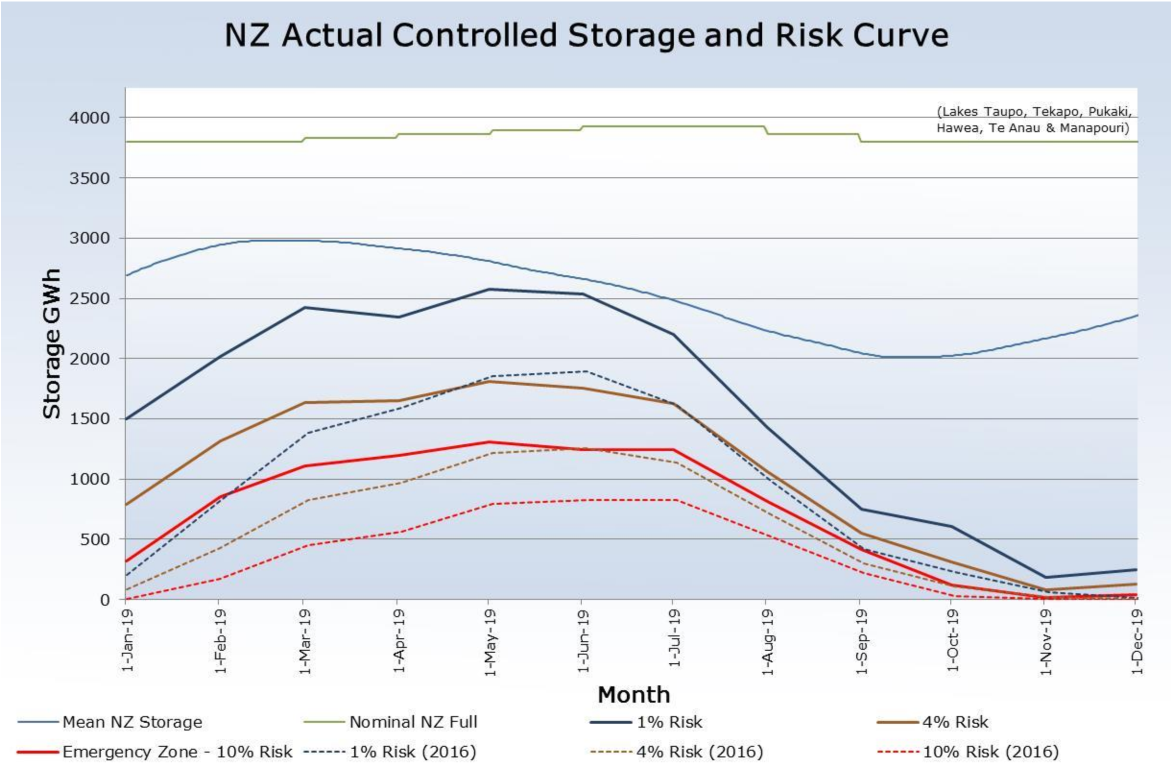

Figure 17: 2016 and 2019 hydro risk curves, 600 MW new generation

Figure 18 shows the SSTs for the 2019 year in the 600 MW scenario. In no inflow sequences does storage trajectory drop below the emergency zone, which is the trigger for an OCC. The System Operator expects an OCC is unlikely in this scenario. However, due to how close to the 10% HRC some of the trajectories get, the System Operator still expects that an OCC may be required in the worst 0.1–1% of inflow sequences.

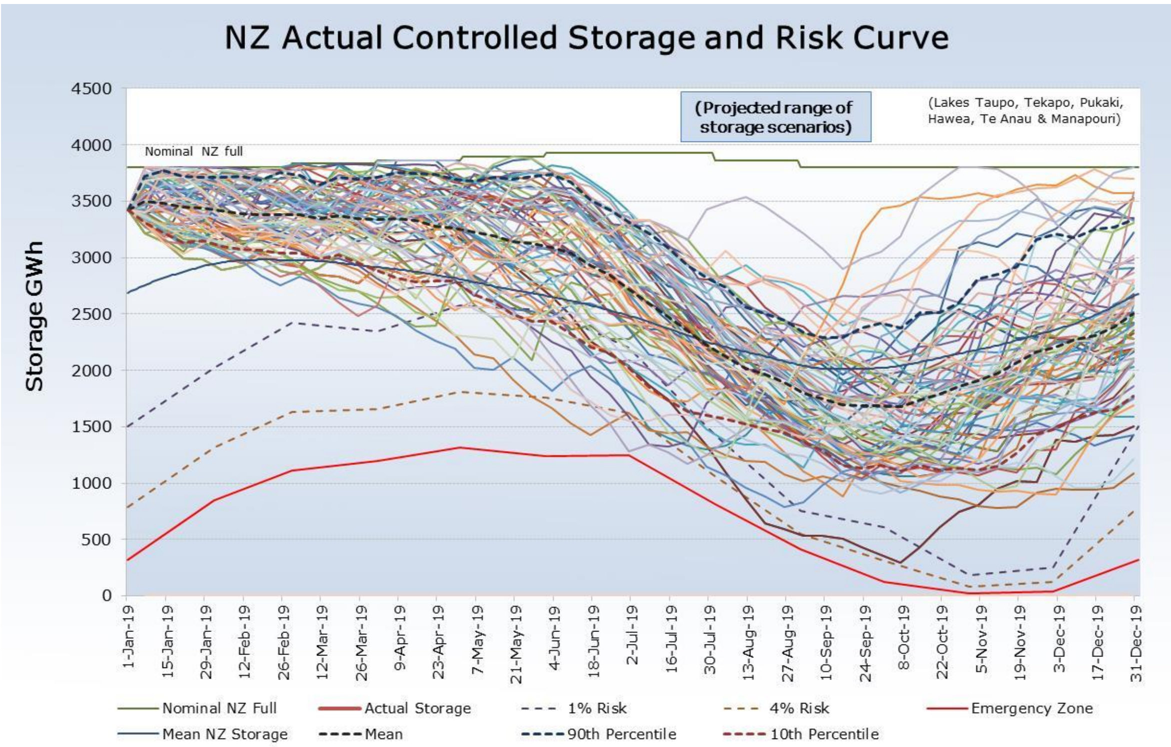

Figure 18: 2019 simulated storage trajectories, 600 MW new generation

6.1.2 Operation of the power system is similar in the 2019 600 MW scenario compared with today

Figure 19 shows thermal generation in the 600 MW scenario to be very similar to that observed in the 2016 scenario but with higher demand. The System Operator still expects hydro storage to be maintained at higher levels in summer and autumn to mitigate the risk of a potential dry winter and thermal generation to be higher on average.

Expected thermal fuel consumption in 2019 in the 600 MW scenario is approximately 62 PJ (average across all inflows). This is an increase from 45 PJ in the 2016 scenario, an increase of 38%. Figure 19, Figure 20 and Figure 21 show there is an increase in gas use effectiveness between the 100 MW scenario and the 600 MW scenario, similar to that observed in the 350 MW scenario. In a dry sequence, more thermal fuel is used, and in a wet sequence, less thermal fuel is used.

Similarly, there is a significant reduction in spill in the 600 MW scenario compared to the 100 MW scenario. On average, spill is expected to be 870 GWh in the 600 MW scenario compared to 1323 GWh in the 100 MW scenario. This spill is roughly the same as that expected in 2016 (882 GWh).

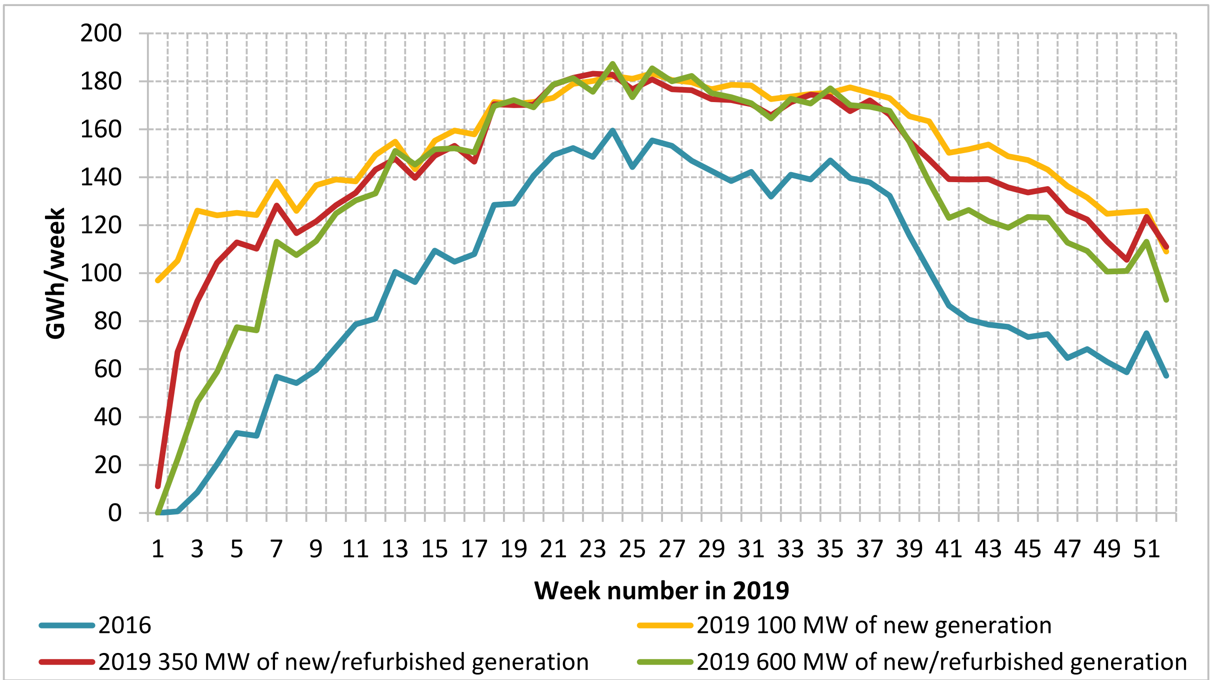

Figure 19: Mean thermal generation (across all inflows) in 2016 scenario, 2019 100 MW scenario, 2019 350 MW scenario and 2019 600 MW scenario

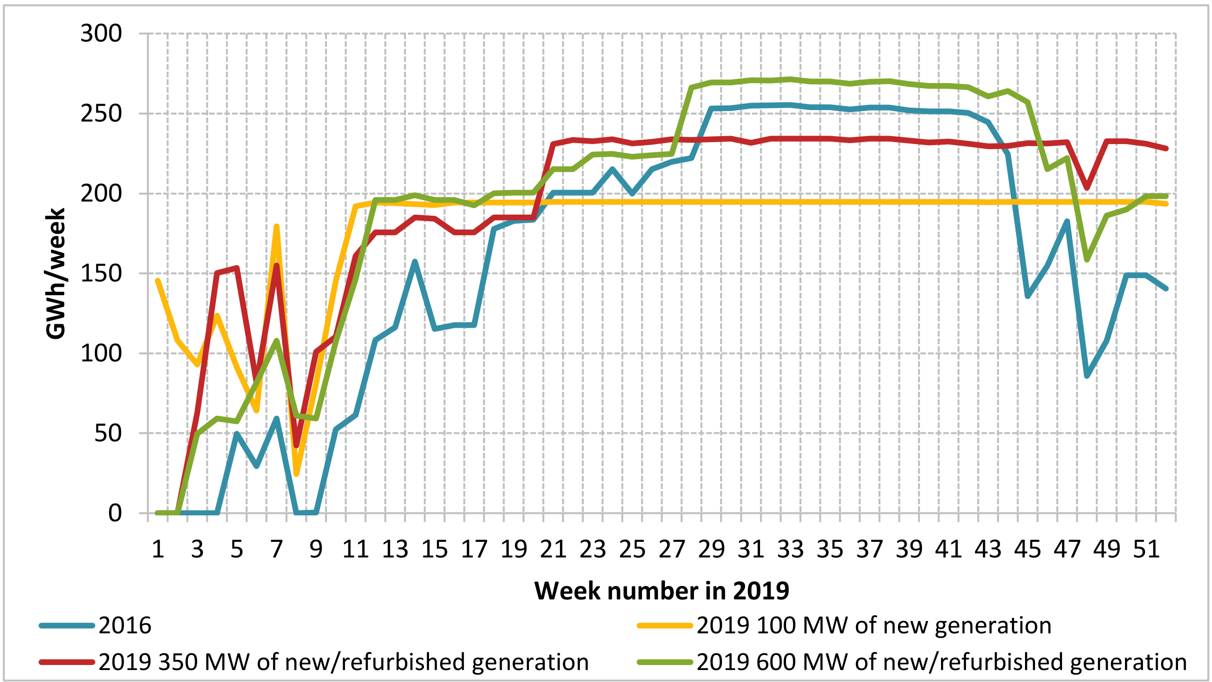

Figure 20: Thermal generation using the 1932 (dry year) inflow sequence in 2016 scenario, 2019 100 MW scenario, 2019 350 MW scenario and 2019 600 MW scenario

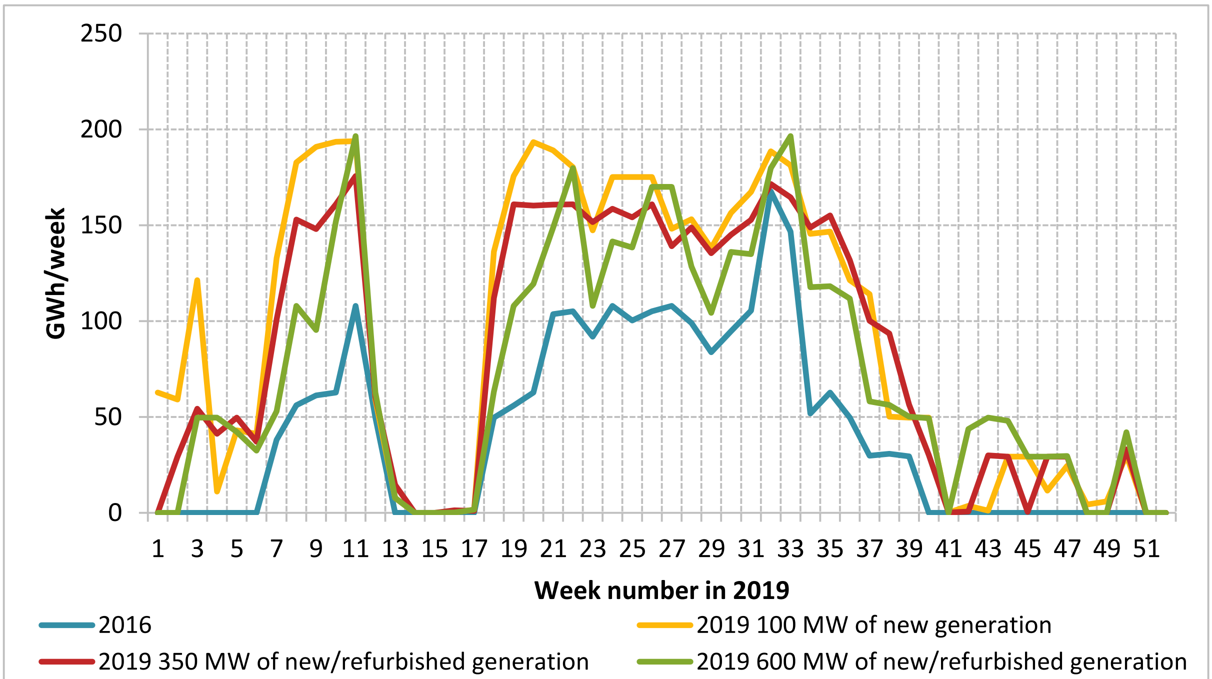

Figure 21: Thermal generation using the 1995 (wet year) inflow sequence in 2016 scenario, 2019 100 MW scenario, 2019 350 MW scenario and 2019 600 MW scenario

Figure 22 shows the difference in operation of the most expensive thermal generator (not including Whirinaki). There is a large difference between the 600 MW scenario and both the previous scenarios (100 MW and 350 MW).

The distribution of capacity factors implies a significant increase in redundancy in the power system and will mean both price levels and system stress should be significantly reduced (compared to the 100 MW and 350 MW scenarios).

A similar outcome is observed in the modelled demand response. In the 600 MW scenario, 172 hours of demand response was dispatched (averaged across all inflow years), compared to the 100 MW scenario of 870 hours. Demand response in this scenario is still higher than that expected in the 2016 scenario (138 hours).

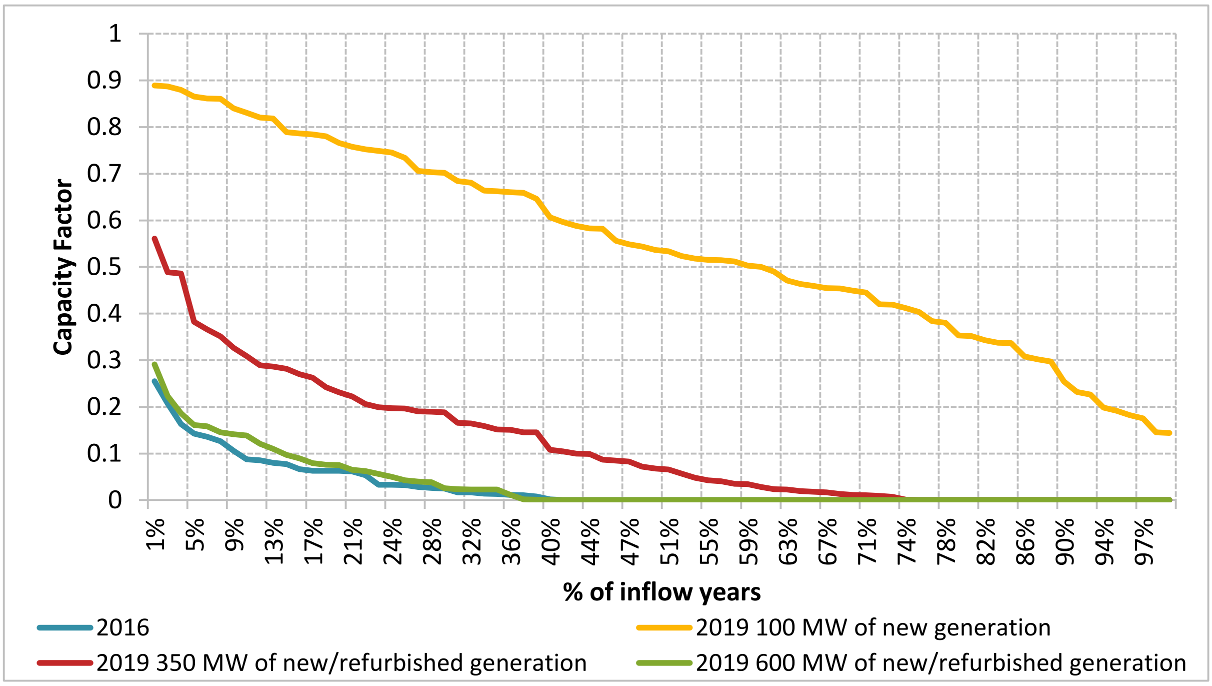

Figure 22: Capacity factor distribution (across inflow sequences) of most expensive thermal generator (excluding Whirinaki)

6.2 PEAK LOAD CAPACITY RISK IN 2019 WILL BE LOW IF DEMAND GROWS AS FORECAST, THERMAL DECOMMISSIONING PROCEEDS AS ANNOUNCED AND 600 MW OF NEW OR REFURBISHED GENERATION IS COMMISSIONED

Modelling results show that, if demand grows as forecast, thermal decommissioning proceeds as announced and 600 MW of new generation is built, peak load capacity risk will be low. There is a low likelihood (approximately 5%) the power system will experience a reserve deficit at some point during the winter and a very low likelihood (close to 0%) the power system will experience energy deficit during peak winter demand.

Figure 23 shows that, in the 600 MW scenario, peak load capacity risk in 2019 will be low. For context, the margin for reserves in the 2015 National Winter Group analysis was 748 MW and the capacity margin was 136 MW.[30]

[30] Similarly, the first draft of the 2016 National Winter Group analysis is 531 MW and -81 MW for margin for reserves and capacity margin respectively.

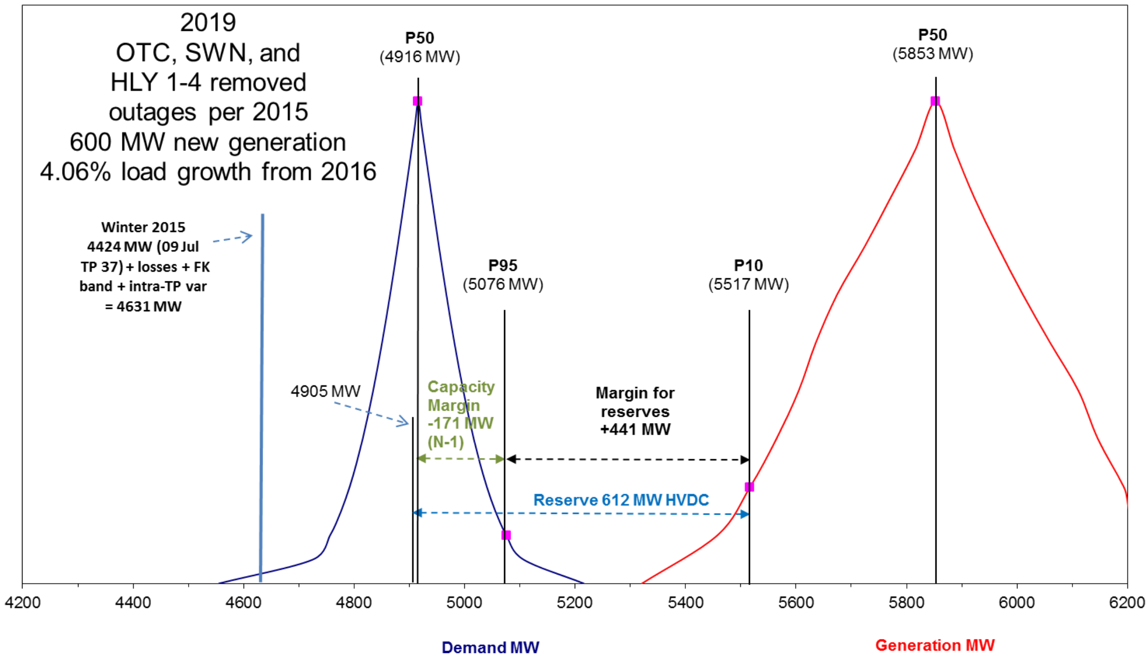

Figure 23: 2019 peak capacity analysis, 600 MW new generation

Using the data in Figure 23, it is possible to estimate the likelihood of an event, such as reserve deficit or scarcity pricing, occurring. The 600 MW scenario implies the following likelihoods:

- Likelihood of a reserve deficit occurring at least once during the winter: 5%.
- Likelihood of scarcity pricing being required (as a result of an energy deficit) at least once during the winter: effectively 0%.

7. Analysis of the scenario where Tiwai closes prior to 2019 shows security of supply risk will be low for energy supply security and high for peak load capacity

7.1 Energy supply security risk in 2019 will be low if demand grows as forecast, thermal decommissioning proceeds as announced, 100 MW of new generation is commissioned and Tiwai closes prior to 2019

There is a significant decrease in energy supply risk in the Tiwai closure scenario compared with the 100 MW scenario. The expected energy supply security risk in this scenario is similar to what is expected in 2016.

The 2019 HRCs in this scenario are similar to those derived for 2016 (May HRCs are 95–105% of 2016 values). An OCC is unlikely to be required, barring unforeseen events such as a major unplanned generation or transmission outage, or unprecedented hydrological conditions.

In this scenario, operation of the power system is likely to be similar to current operation.

This scenario includes the following core assumptions:

- Demand growth averaging 1.38% p.a. until 2019.
- Closure of the Tiwai aluminium smelter prior to 2019[31], which removes 572 MW of load from the lower South Island.
- 100 MW of new gas-fired generation that is expected to be built.
- Median hydrology in 2018 and a Huntly decommissioning date of 1 January 2019 (to determine a start storage value).

7.1.1 An OCC is not likely in the Tiwai closure scenario

Figure 24 shows the 2019 HRCs using the Tiwai closure scenario assumptions.

The impact of the lower South Island security constraint has not been explicitly modelled. This constraint monitors circuits into and out of the lower South Island region and could potentially limit the flow out of the region should Tiwai close. The likely consequence of this constraint would be to increase the HRCs slightly. However, the System Operator does not expect this to materially affect the HRCs.

[31] In this scenario Tiwai is assumed to close at the same time as the Huntly Rankine units.

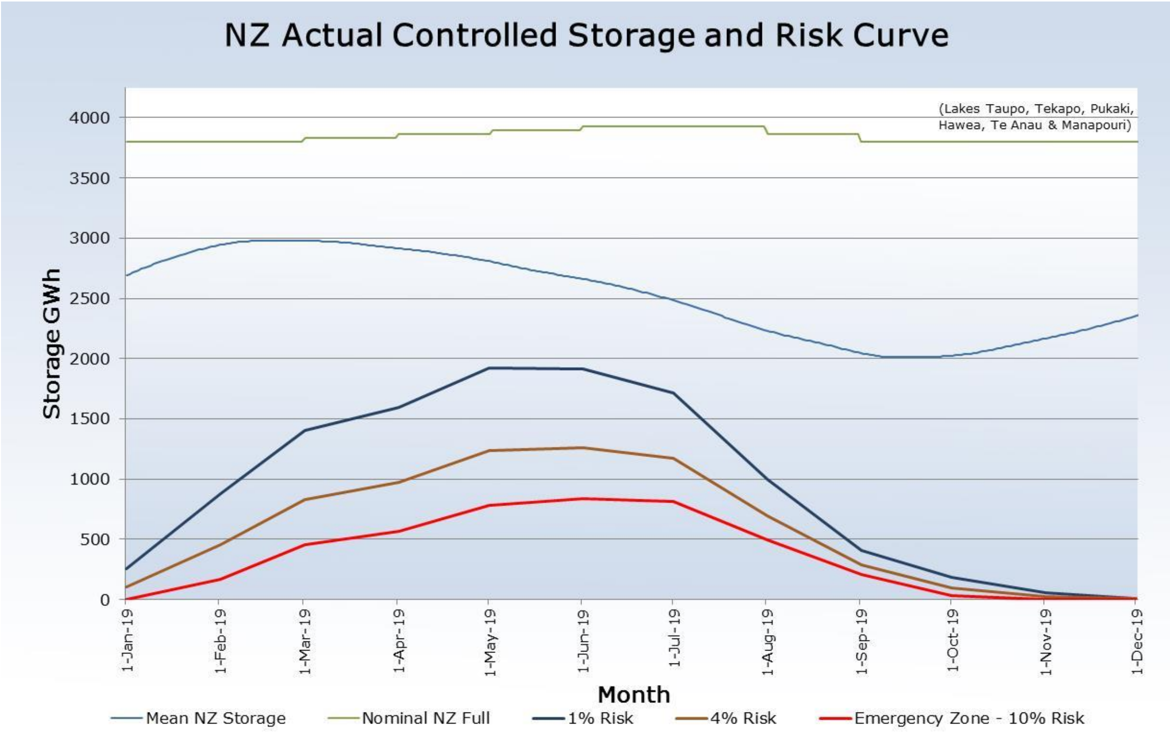

Figure 24: 2019 hydro risk curves, Tiwai closure

Figure 25 shows the SSTs for the 2019 year in the Tiwai closure scenario. No storage trajectories drop below the emergency zone, the trigger for an OCC. The System Operator does not expect an OCC will be required in this scenario.

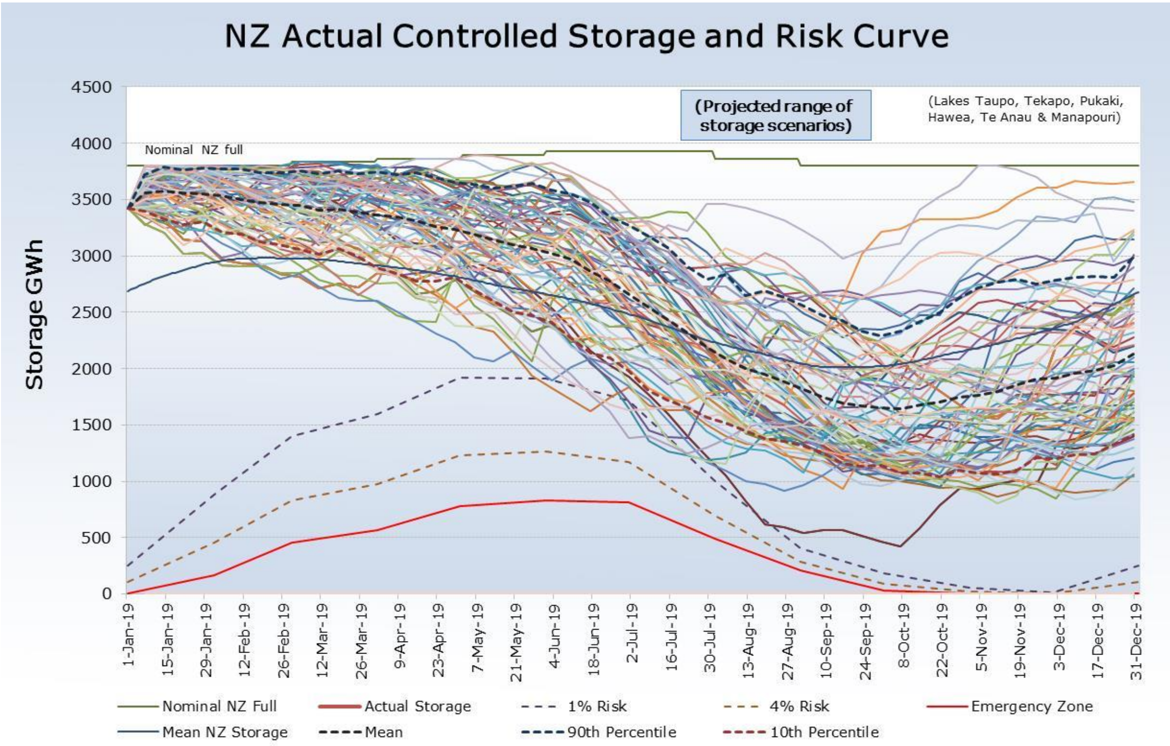

Figure 25: 2019 simulated storage trajectories, Tiwai closure

7.1.2 Operation[32] of the power system is similar in the 2019 Tiwai closure scenario compared with today

The following charts compare operation of thermal generation between the 2016 scenario and the Tiwai closure scenario in 2019.

Figure 26 shows thermal generation in the Tiwai closure scenario to be much lower than that observed in the 2016 scenario.

Figure 27 shows that, even in a dry year, the thermal generation will not be required to generate at high levels outside of the winter months (currently typical in the power system). Figure 28 shows low demand for thermal generation in a wet year.

Expected thermal fuel consumption in 2019 in the Tiwai closure scenario is approximately 29 PJ (average across all inflows). This is a decrease from 45 PJ in the 2016 scenario. Figure 29 shows the distribution of thermal fuel consumption across inflow sequences.

In the Tiwai closure scenario, there is a significant increase in spill. On average, the System Operator expects spill to be 2186 GWh in 2019 compared to 1323 GWh in the 100 MW scenario and 882 GWh in the 2016 scenario.

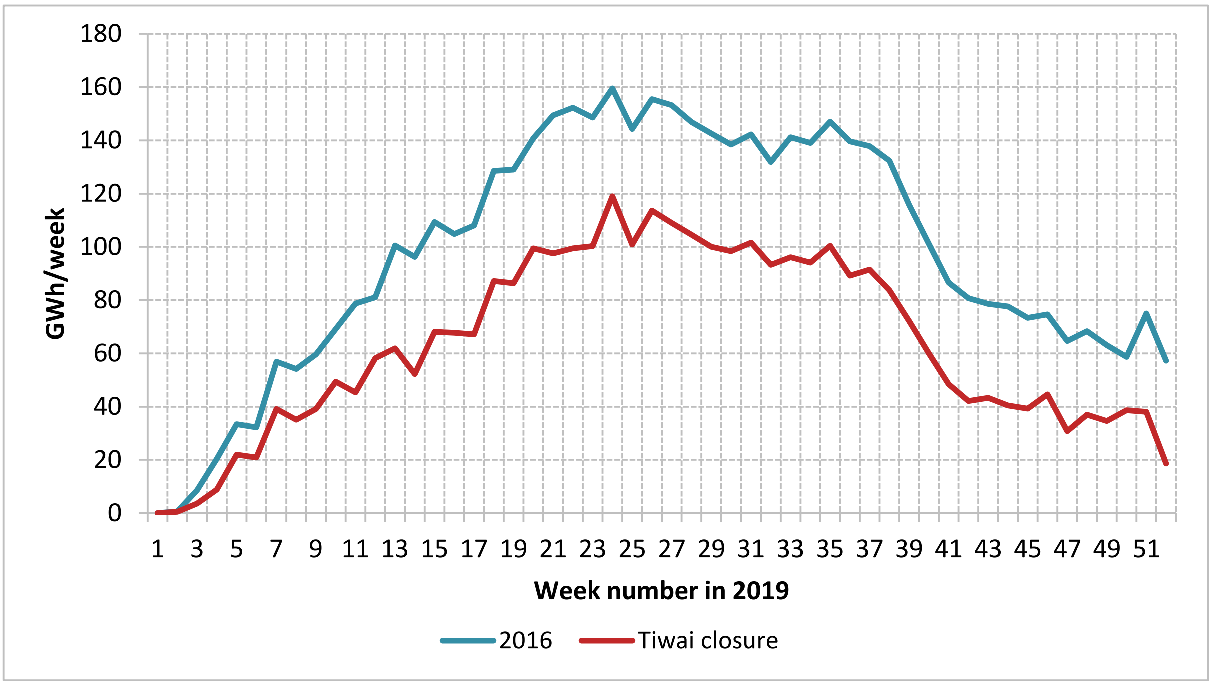

Figure 26: Mean thermal generation (across all inflows) in 2016 and 2019 Tiwai closure scenario

[32] Note that this section only focuses on the results of the SDDP modelling and does not directly consider peak capacity issues or implications.

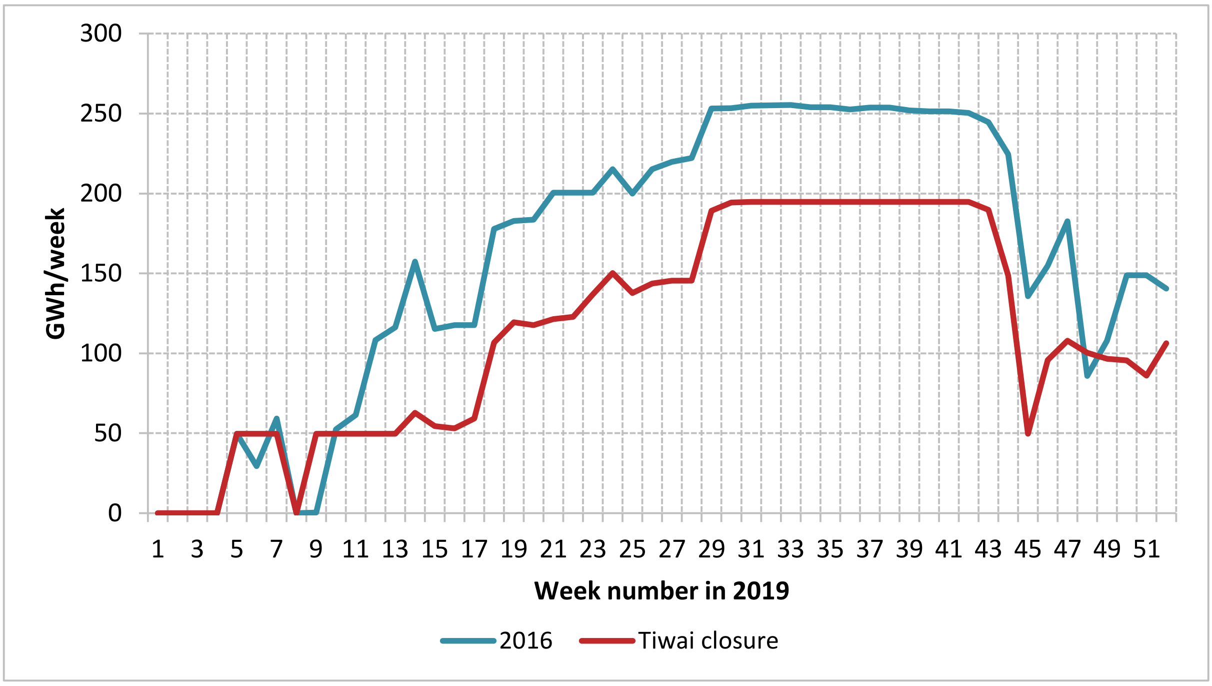

Figure 27: Thermal generation using the 1932 (dry year) inflow sequence in 2016 and 2019 Tiwai closure scenario

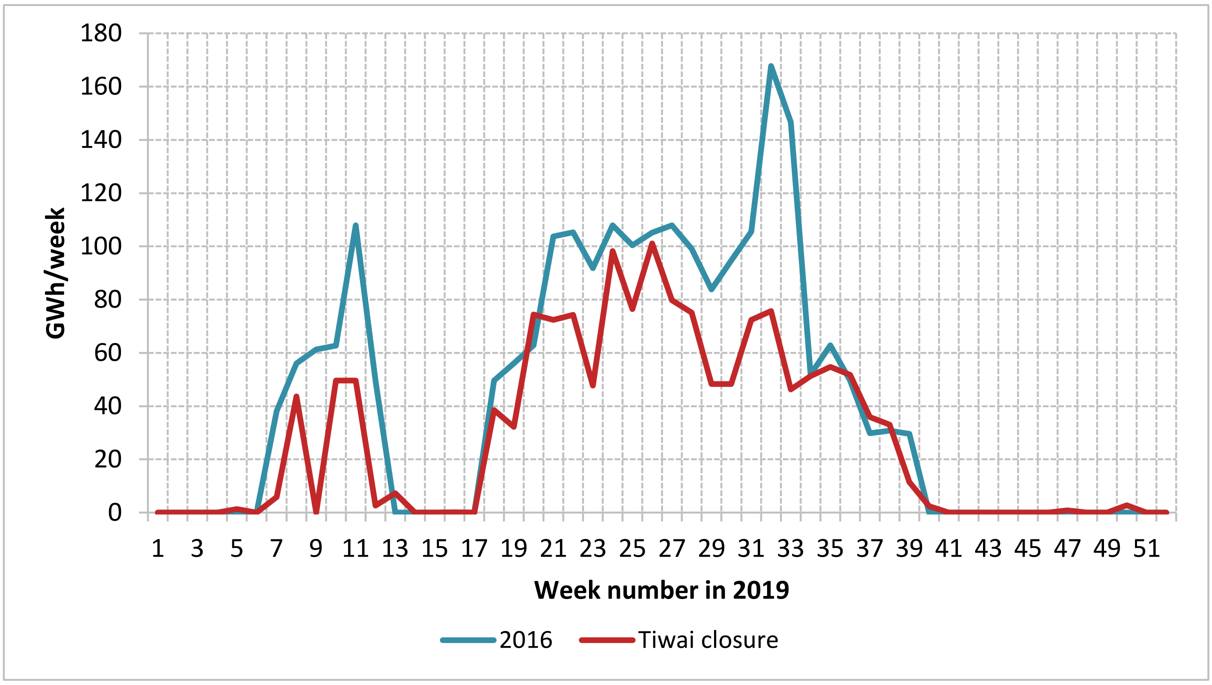

Figure 28: Thermal generation using the 1995 (wet year) inflow sequence in 2016 and 2019 Tiwai closure scenario

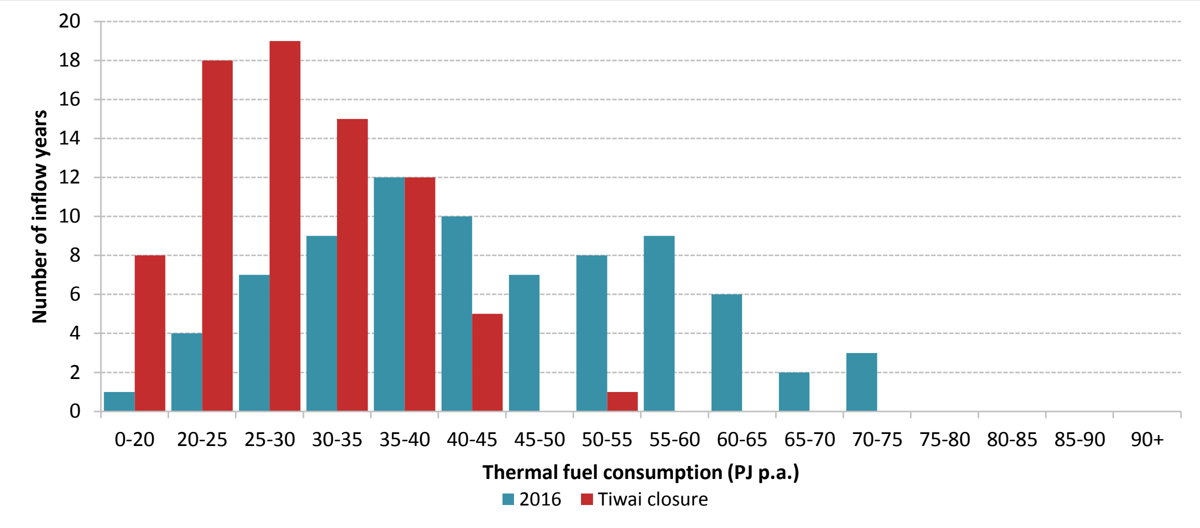

Figure 29: Thermal fuel consumption, 2016 and 2019 Tiwai closure scenario

Figure 30 shows the difference in operation of the most expensive thermal generator (not including Whirinaki). The distribution of capacity factors implies a significant increase in redundancy in the power system and will mean both price levels and system stress is expected to be similar to what is currently experienced in the wholesale electricity market.

A similar outcome is observed in the modelled demand response. In the Tiwai scenario, 188 hours of demand response is dispatched (averaged across all inflow years) compared to 138 hours in the 2016 scenario.

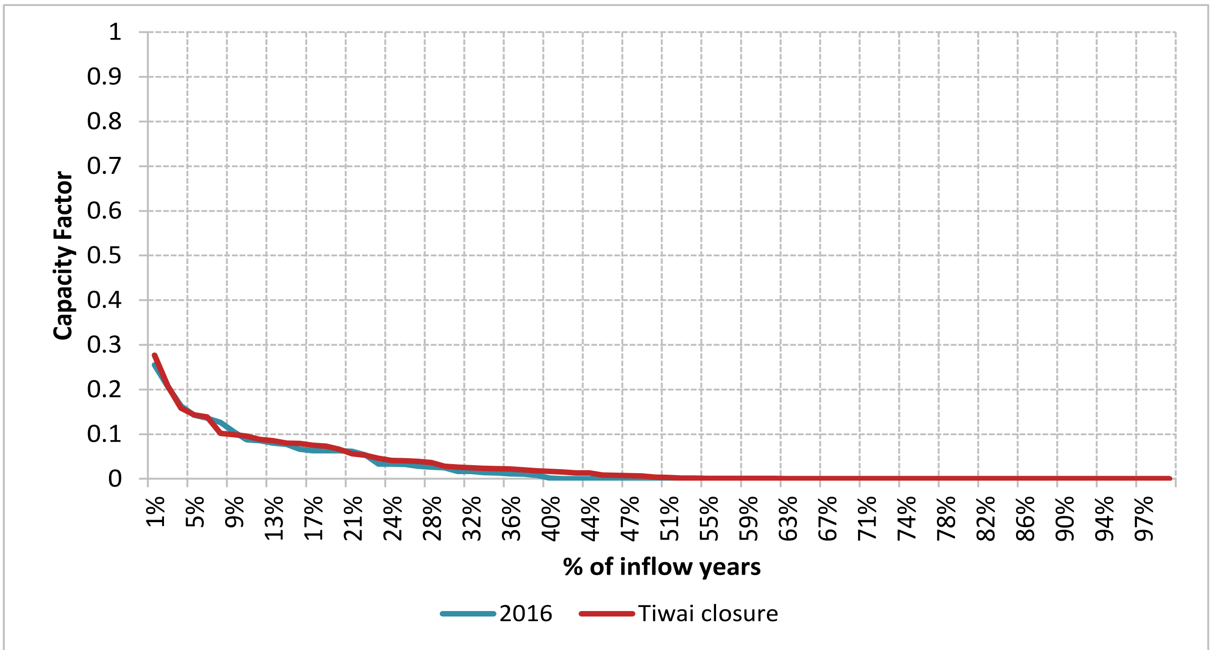

Figure 30: Capacity factor distribution (across inflow sequences) of most expensive thermal generator (excluding Whirinaki)

7.2 PEAK LOAD CAPACITY RISK IN 2019 WILL BE UNCHANGED FROM THE 100 MW SCENARIO IF TIWAI CLOSES

Due to HVDC transmission limitations, the Tiwai closure scenario has identical peak load capacity results as those observed in the 100 MW scenario (see Figure 9). This means the peak load capacity risk in 2019 in the Tiwai closure scenario will be high.

8. NOTABLE IMPLICATIONS

8.1 TIWAI CLOSURE UNCERTAINTY COULD INFLUENCE INVESTMENT DECISIONS

The future of the Tiwai smelter (and, by extension, demand growth) could influence future investment in new generation. The risk of Tiwai closure may affect investment decisions and therefore limit new generation developments.

Figure 31 illustrates the risk implicit in future generation investment. The System Operator expects the amount of thermal generation required in a Tiwai closure scenario will be lower than what is currently observed.

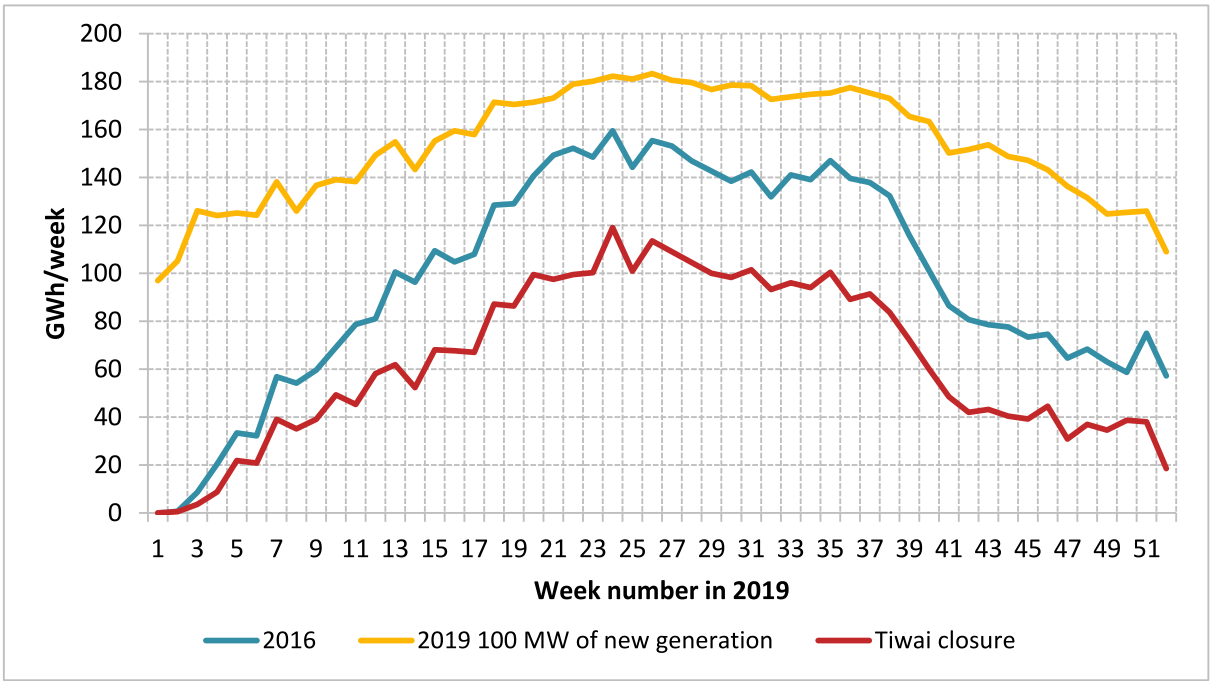

Figure 31: Mean thermal generation (across all inflows); 2016 scenario, 2019 100 MW scenario and 2019 Tiwai closure scenario

The analysis above does not consider North Island peak capacity requirements. Section 4.2 explains the high level of risk faced in the North Island with no new generation investment, regardless of Tiwai demand, so while Tiwai risk reduces the potential value of energy supply investment, there is still a strong signal for peak supply investment regardless of Tiwai demand.

8.2 THE POWER SYSTEM FACES AN INCREASED DEPENDENCY ON GAS INFRASTRUCTURE

In the three generation scenarios (100, 350 and 600 MW scenarios), there is an increase in gas consumption – ranging from 18–25 PJ above what is expected in 2016 (45 PJ).

Increased gas consumption implies a greater dependency on gas infrastructure[33] for security of supply. An extended outage of the Maui pipeline could, for example, have significant ramifications for security of supply.

In the 100 MW scenario, 24 PJ of gas is consumed at the Huntly node. If there was an outage on the Maui pipeline, this energy would need to be sourced elsewhere. In situations where the power system is under stress, some generation reliant on gas may not be available, and it is possible the power system could experience localised (or island or national, depending on the circumstance) shortages.

8.3 THE POWER SYSTEM FACES AN INCREASED DEPENDENCY ON HVDC TRANSMISSION

Following decommissioning of North Island thermal generation, the criticality of the HVDC, especially when transferring South Island capacity north, will significantly increase.

The HVDC is likely to transfer, on average, higher levels of capacity north and do so more often. Due to the lack of North Island capacity, South Island generation will be essential to serving North Island demand. This is different to the present situation where South Island generation is dispatched to meet North Island demand on an economic basis.

Figure 32 shows the load duration curve compared with North Island capacity. The underlying requirement for HVDC transfer can be shown by the section of the load duration curve (period of time demand is above a certain level) that is above the maximum capacity. Figure 32 shows that, in 2019, HVDC transfer north will be required in order to meet North Island demand approximately 12% of the time.

The increased dependency on the HVDC will also mean that planned maintenance will be more difficult to schedule and will face an increased risk of being deferred or cancelled (and the costs associated with deferring or cancelling an outage)[34].

[33] Including supply and transmission infrastructure.

[34] This applies to all infrastructure that has an influence on security of supply risk: it is likely planned transmission and generation outages will face increased costs in scenarios where security of supply risk is higher.

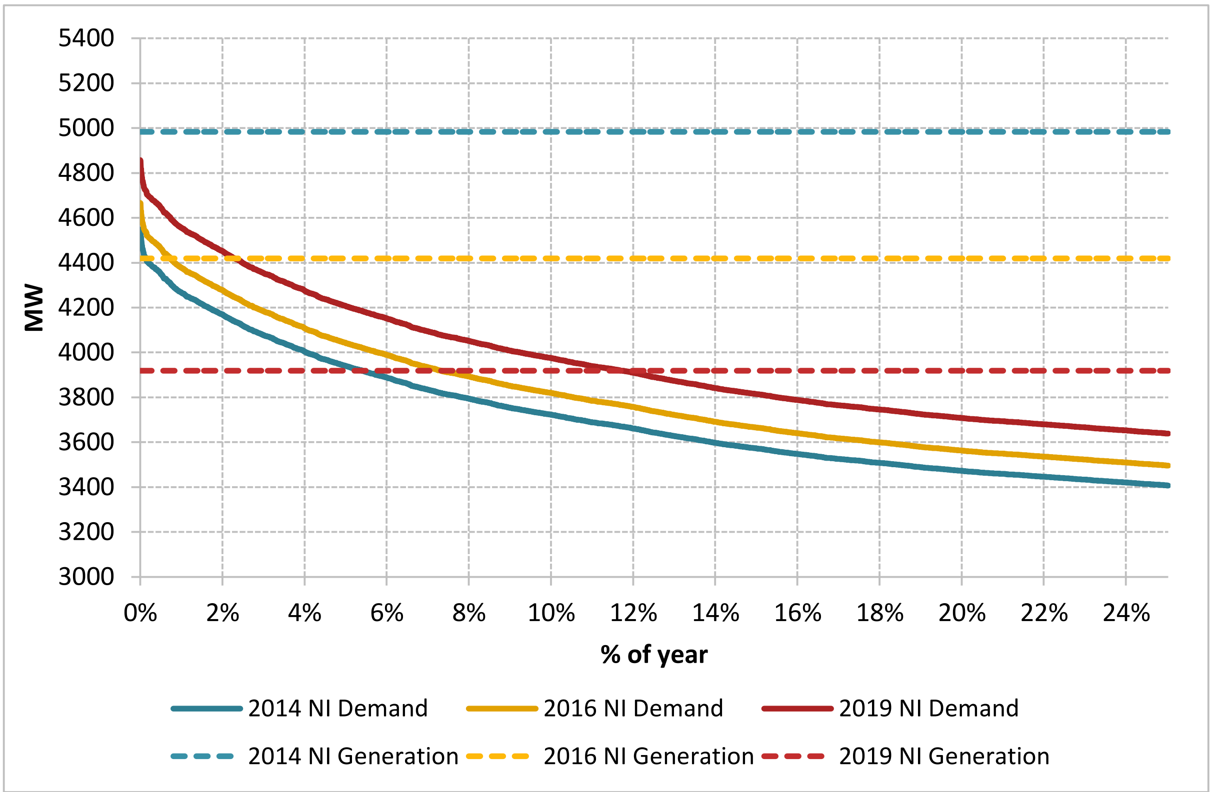

Figure 32: North Island load duration curves and generation capacity for 2014, 2016 (expected) and 2019 (100 MW scenario, expected)

8.4 REMAINING THERMAL GENERATION IS EXPECTED TO HAVE INCREASED CAPACITY FACTORS FOLLOWING THERMAL DECOMMISSIONING

In the scenario where 350 MW of new generation is built, the expected capacity factor of thermal generation (totalled across all thermal generation excluding Whirinaki) is 59% on average. For context, the capacity factor of thermal generation in 2014 (which had been slightly below average hydrology) was 38%. Therefore, remaining thermal generation in 2019 is not likely to experience the low capacity factors currently experienced with existing thermal generation.

While this conclusion is slightly contradictory to the implication observed in section 8.1, this can be seen as the upside value of investment in new generation (compared to the downside risk identified in section 8.1).

This increase in capacity factors is evidenced in Figure 8, Figure 15 and Figure 22, which all show an increase in thermal capacity factor. These charts refer to the capacity factor of the most expensive thermal generation in the model, any other thermal generation can be assumed to have the same or greater capacity factor than is observed in these charts (since the most expensive generator will generally have the lowest capacity factor).