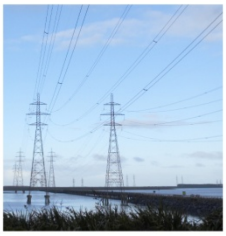
WAIKATO AND UPPER NORTH ISLAND VOLTAGE MANAGEMENT LONG-LIST CONSULTATION

INCLUDING INVITATION FOR INFORMATION ON NON-TRANSMISSION SOLUTIONS

Transpower New Zealand Limited

July 2016

Keeping the energy flowing

TRANSPOWER

Transpower New Zealand Limited The National Grid

Contents

1 Executive summary

There have recently been actual and announced decommissioning of major generation plants in the Upper North Island, being the region north of Huntly and including Auckland. These so-called 'thermal decommissionings' are:

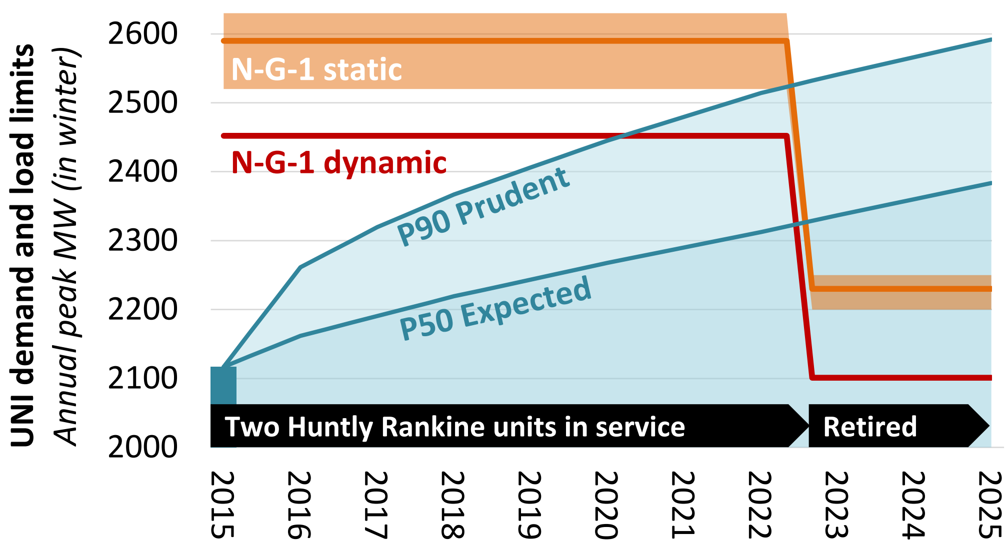
- 380 MW Otahuhu combined cycle unit (ceased generation in September 2015)
- 175 MW Southdown generation station (ceased generation in December 2015)
- 500 MW Huntly 'Rankine' units 1 and 2 (announced, to be retired end of 2022).

These are significant changes for the New Zealand power system. Transpower conducted a number of analyses in late 2015 and early 2016, and identified issues with both voltage management in Waikato and the Upper North Island, and thermal transfer into the region. The investigation covered by this consultation document focuses on the voltage management issues. The thermal transfer issues are currently under investigation within Transpower, and may lead to a similar consultation to this one in due course.

The principal issue is voltage stability in the Upper North Island. Transpower has analysed the issue against:

- the 'N-G-1' security standard, which requires that the system be robust to a single credible contingency (asset failure) while one generator is out of service
- both static and dynamic voltage stability limits
- both expected ('P50') and prudent ('P90') peak demand forecasts.

The results are summarised in the following figure:



Our analysis indicates that the power system will not be able to supply the peak Upper North Island load from winter 2021, even with two Rankine units available to provide active and reactive power support, under the N-G-1 security standard. The need here is in the order of 100 MW equivalent.

There is considerable uncertainty in this need date due to uncertainty in both the voltage stability limits and the demand forecast. We will refine our analysis throughout this investigation to quantify and reduce this uncertainty where possible.

In addition, once the Rankine units retire, there is a much larger quantum of need, in the order of 400 MW equivalent and increasing against the prudent forecast we use for planning purposes. Even under the expected forecast, the quantum of this need is over 200 MW equivalent and increasing. Given that the Huntly Rankine units are expected to be decommissioned at the end of 2022, this need has to be met before winter 2023.

Given the time for analysis, regulatory approval, procurement, build and commissioning, these need dates are tight.

To meet this need requires either:

- generation investment at or north of Huntly
- increased reactive support in the Waikato and/or Upper North Island
- reduced winter peak load in the Upper North Island.

The need is such that it is unlikely to be met by a single solution – a range of components, commissioned at various locations and over time, is likely to be required. We have developed a draft long-list of components that we present in this consultation document. The draft long-list includes reactive power devices, other transmission assets, system operations, market generation and demand-side participation (including embedded generation).

Many of these components could be provided as non-transmission solutions through a grid support contract with Transpower.

This consultation document seeks your feedback on:

- our assessment of the need
- the long-list of components, especially with regard to non-transmission solutions
- any specific non-transmission solutions of which you are aware
- the assumptions (including demand forecasts and generation scenarios) that we will use to identify a preferred solution

We seek written feedback by 5pm on Tuesday 16 August 2016. Responses should be in electronic form and emailed to WUNIVoltageManagement@transpower.co.nz. More details are contained in section 8.

Thank you for your interest in and assistance with this project.

2 Definitions

2.1 Glossary

ACOT	Avoided cost of transmission
CapexIM	Capital Expenditure Input Methodology Determination 2012, New Zealand Commerce Commission
Code	Electricity Industry Participation Code 2010
DGPP	Distributed generation pricing principles
EDGS	Electricity Demand and Generation Scenarios
GSC	Grid Support Contract, used for non-transmission solutions
GUP	Grid upgrade plan
GXP	Grid Exit Point
HVDC	High-voltage direct current
MBIE	Ministry of Business, Innovation and Employment
MCP	Major Capex Proposal as defined in the CapexIM
Mvar	Mega volt ampere reactive
MWh	Megawatt hour of electrical energy
N-1, N-G-1	Security standards – described in section 2.3
Rankine	A type of coal/gas plant owned and operated by Genesis Energy at Huntly
RCPD	Regional Coincident Peak Demand of the TPM
RFP	Request for Proposal
SoO	Statement of Opportunities
STATCOM	Static synchronous compensator
SVC	Static VAR compensator
TPM	Transmission pricing methodology, defined in Schedule 12.4 of the Code
Transpower	Transpower New Zealand Limited, owner and operator of New Zealand's high-voltage electricity network (the national grid).
UNI	Upper North Island
UNIDRS	Upper North Island Dynamic Reactive Support (a specific GUP)
VOLL	Value of lost load
WUNI	Waikato and Upper North Island

2.2 Region of interest

The region of interest is the Waikato and Upper North Island (UNI), being the 220 kV system from Hamilton (HAM) north, and the 110 kV system from Arapuni (ARI) north.

This region is illustrated schematically in Figure 2-1 and geographically in Figure 2-2 below.

Figure 2-1: Illustration of Waikato and UNI transmission system (schematic)

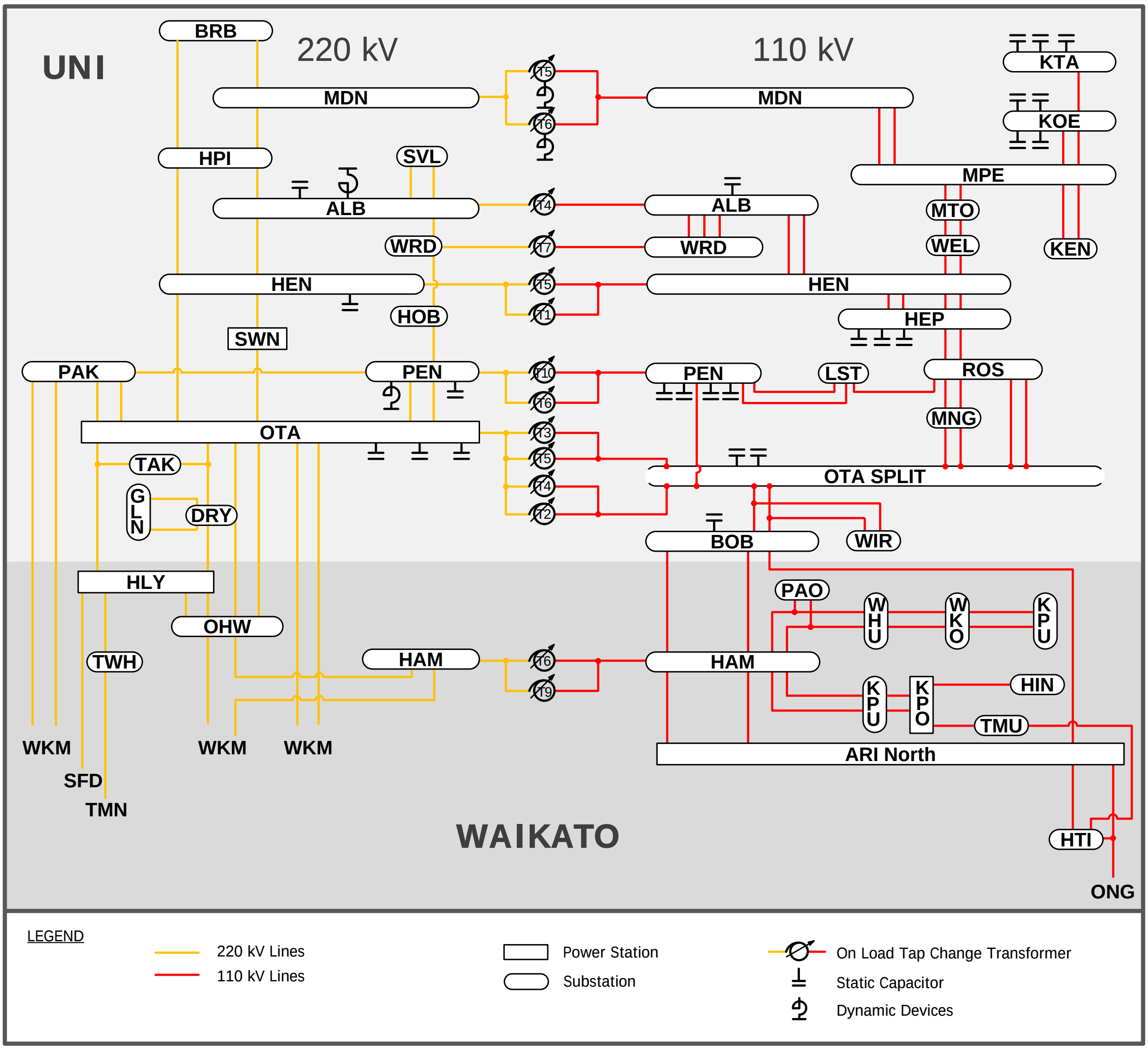


Figure 2-2: Illustration of Waikato and UNI transmission system (geographic)

2.3 Security standards

Transpower uses ‘deterministic’ security standards as a baseline for its system analysis: N-1 and N-G-1.

N-1 refers to planning the system to be robust to a single failure (the “1”) in real time. That is, planning for a system that can be operated such that supply can be maintained without damaging transmission or connected assets, should an asset (e.g. a circuit or transformer) fail.

N-G-1 refers to planning the system such that it can maintain N-1 security when a generator is not available, for either a planned or unplanned (forced) outage. For the Waikato and the UNI, since the thermal decommissionings, the largest generation plant is Huntly unit 5, which would be the ‘G’ for this region. An example of where a generation failure has happened is presented in this case study.

Case study

On 16 May 2016 shortly before 6 pm Huntly unit 5 unexpectedly failed. Prior, the generation output was around 375 MW. The forced outage lasted nearly 24 hours. The unit was then returned to service, ramping up to around 200 MW until midday on the 18th when it started ramping up to full generation.

2.4 Expected and prudent peak demand forecasts

We plan our investments against a ‘prudent’ peak demand forecast. The prudent peak demand forecasts represent a 10% probability of exceedance forecast in the first seven years then assume growth rates equal to the expected forecast. As a result, the annual growth in the prudent peak forecast is higher than the annual growth in the expected peak forecast for the first seven years until 2022 inclusive. After that time, the two forecasts are almost parallel. Prudent forecasts are sometimes referred to as ‘P90’ forecasts.

We conduct our economic analysis against an expected peak demand forecast. The expected peak demand forecast can be interpreted as representing a 50% probability of exceedance. It is often referred to as a ‘P50’ forecast.

In both the Waikato and the Upper North Island regions, the annual peaks have occurred in the winter, and we assume on the basis of our modelling that this will continue.

Our peak demand forecast assumptions are presented in section 7.1.1.

2.5 Static and dynamic terminology

This section explains some technical terms used throughout this consultation paper.

Voltage stability refers to the ability of a power system to maintain steady voltages at all busses in the system after being subjected to a disturbance, such as an event that disconnects grid, load or generation equipment. Instability is due to the loss of operation equilibrium, resulting in a progressive fall or rise of voltages of some busses.

Voltage stability on a power system requires both long-term or static stability, and short-term or dynamic stability in the event of a fault on the system.

- We determine static voltage stability limits using a steady-state load-flow analysis which captures the system behaviour as it settles from one steady-state equilibrium to another. This method however cannot easily account for controls that depend on the system's time evolution, for which a dynamic simulation is performed.
- We determine dynamic voltage stability limits using dynamic analysis which captures the response of preventive or corrective controls on the system (including generation plant, reactive devices, protection relays and motor load) on the system during the milliseconds and seconds after a disturbance, while the system is adjusting to its new steady-state equilibrium.

Static reactive devices such as capacitor banks provide binary on/off response and are generally used to support static voltage stability.

Dynamic reactive devices such as SVCs, STATCOMs and synchronous condensers provide fast continuous response and are generally used to support dynamic voltage stability.

3 Need

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).

The Integrated Transmission Plan 2015[2] highlighted grid backbone issues that could arise following these retirements.

Transpower conducted a number of studies as both system operator and grid owner to determine the impacts on the power system, covering different time horizons. A summary of the results covering time horizons from 2018 are presented below in sections 3.1 and 3.2.

Since then, in late April 2016, Genesis Energy announced a delay in the decommissioning of Huntly units 1 and 2 (the Rankine units) to the end of 2022 – this is discussed in section 3.3 below.

As some of the need (e.g. for generation security of supply) will be met by the market, and some by Transpower, section 3.4 defines the scope of this project.

Finally, the assessed need, taking into account Genesis Energy's decision and extending the period of analysis, is presented in section 3.5.

Note that, normally, transmission needs would be signalled ahead through Transpower's transmission planning report. However these decommissionings were signalled after the last 2015 transmission planning report[3].

3.1 Grid owner's findings assuming Rankine retirement in 2018

In April 2016 Transpower as grid owner published a report on Upper North Island operational limits following Huntly Rankine unit retirements[4].

The purpose of these investigations was to define the issues. This involves computer-modelling the North Island transmission system, taking the recent and proposed Upper North Island generation decommissioning into account and projected load growth.

The system is tested by modelling a range of credible contingencies (failures of equipment such as circuit outages). This testing is looking for system conditions where the

[1] The region defined as the Upper North Island is defined in Section 2.2.
[2] See www.transpower.co.nz/industry/regulatory-control-periods/rcp2/updates
[3] See www.transpower.co.nz/resources/transmission-planning-report-2015.
[4] See www.transpower.co.nz/upper-north-island-generation-decommissioning-report-and-appendices.

transmission system cannot supply the forecast load without constraints such as overloaded circuits, over or under-voltage and static/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).

The key findings were as follows:

3.1.1 Upper North Island reactive support - dynamic analysis

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 voltage stability limits will be 2534 MW and 2219 MW respectively. This compares to the 2015 winter peak of 2150 MW, and the 2020 prudent peak 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.

In addition, the results of this investigation indicate a possible voltage stability issue in the wider Hamilton area.

3.1.2 Upper North Island reactive support – load flow analysis

Upper North Island static voltage stability limits may be exceeded when the announced Huntly generation decommissioning goes ahead. Insufficient dynamic voltage support (rather than static support) is expected to be the first constraint.

3.1.3 Thermal constraints between Whakamaru and Auckland

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).

3.1.4 Review of existing constraints south of Whakamaru

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.

3.1.5 Waikato 110 kV issues

The Arapuni bus split will remain open in the interim, 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[5] in place prior to the generation decommissioning being announced.

3.1.6 High voltage management in the Upper North Island.

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 need for further investment.

3.2 System operator's findings assuming Rankine retirement in 2018

In April 2016 Transpower as system operator published a report on Upper North Island Operational Limits Following Huntly Rankine unit retirements[6]. This report concludes that:

- If the Huntly Rankine units are decommissioned in 2018, operational measures may be required to manage both thermal capacity and voltage stability issues during contingency and outage conditions in the Upper North Island in winter.
- Although the Upper North Island power system will be more susceptible to risk exposures without the Rankine units, in 2018 the identified thermal capacity and voltage stability issues can be managed satisfactorily with transmission and generation assets currently in service and available to the market by utilising existing operational measures, however in 2019 and 2020 there is a risk that load management may be required at peak times.

3.3 Impact of delay in Rankine retirement

In late April 2016, Genesis announced that it "has entered into four-year bilateral commercial arrangements with other market participants that will keep two Rankine Units available to the end of 2022. The new contracts will cover the operational and capital costs of keeping the units in the market."[7]

Meridian, one of the counterparties, describes its contract as "a four year swaption contract with Genesis Energy to replace its current arrangement which expires on 31 December 2018. The new agreement begins on 1 January 2019 and ends on 31 December 2022. The

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

[6] See https://www.systemoperator.co.nz/activites/current-projects/impact-thermal-generator-decommissioning

[7] See www.nzx.com/companies/GNE/announcements/281406

structure continues to allow for 100 MW to be available year round, with an additional 50 MW available from 1 April to 31 October in each year of the contract."[8]

Transpower has discussed with Genesis Energy how these contracts will affect the operation of the Huntly Rankine units from 2018 to 2022, and we appreciate Genesis's assistance and openness. While some details are confidential, we are confident from these discussions that we can assume for planning purposes that from 2018 to 2022:

- Genesis will operate two Rankine units in the manner in which they are currently operated, being offered into the market for MW and Mvar whenever commercially appropriate
- Planned outages of Huntly units (including unit 5) will continue to be based on ensuring that, between the Rankine units and unit 5, two units will be available
- Genesis will manage its coal and/or gas fuel contracts and stocks around these availability targets
- Complete decommissioning of the Rankine units in December 2022
- If Tiwai announces that it will close prior to December 2022 (that date being the closure, not the announcement), Genesis may retire the Rankine units earlier, but also may keep them open if market conditions permit.

3.4 Scope of this project

As described above, it is expected that a mix of thermal and static and dynamic voltage stability issues will arise from the thermal generation decommissionings coupled with regional load growth.

The scope of this project is to consider solutions to the forecast static and dynamic voltage stability issues.

Current Transpower projects with potential interactions with this project include:

- The installation and commissioning of a reactive power controller for the Upper North Island (under the UNIDRS GUP approval)
- Transpower's ongoing Demand Response programme[9].
- Thermal issues are currently the subject of an investigation within Transpower, which may or may not result in a proposal to invest.

There are also some ongoing investigations and related projects, including:

- Investigations are underway to assess options for resolving central North Island 110 kV network constraints on the Bunnythorpe–Mataroa circuit, and retaining the Arapuni bus split.
- 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,

[8] See www.nzx.com/companies/MEL/announcements/281407

[9] See www.transpower.co.nz/keeping-you-connected/demand-response.

Taranaki, Wellington and the South Island, will be initiated when there is more certainty on future generation investment location, size and timing.

- In addition, we may start an investigation into management of high voltages in the Upper North Island in late 2016 or early 2017 depending on the preferred solution to this project.

3.5 Need for investment

Following the removal of thermal generation, the load in the Upper North Island (UNI) will be predominantly supplied from remote generation in the Wairakei ring, central North Island and Taranaki areas. This increases the loading on transmission lines, making the UNI susceptible to poor voltage performance. We have identified that dynamic voltage stability after a major fault is the first limiting factor in supplying the UNI load (see section 3.1). The studies also indicate a possible voltage stability issue in the wider Hamilton area. Further work has been carried out extending the need assessment to include the Waikato region. The findings are presented in the following section.

Due to the features of the New Zealand's transmission network, the Waikato region (which also connects to the main corridor of the 220 kV transmission circuits into the Auckland) – and Northland regions have an impact to the need for voltage support. Both the dynamic and static voltage stability limits in the UNI have reduced since the removal of generation, and worsen when taking into account the load in the Waikato region (compared to the voltage stability limits in section 3.1.1). For that reason, the investment need covered under this project also looks into the reactive support requirement in the Waikato region.

3.5.1 Voltage stability limits

This section describes the voltage stability limits for the combined Waikato and Upper North Island region.

Following the decommissioning of 380 MW Otahuhu combine cycle unit and 175 MW Southdown generation station in 2015, the dynamic voltage stability load limit[10] in the UNI reduces to around:

- 2,450 MW under N-G-1 security criteria. This is assuming the two Huntly Rankine units are available providing full active and reactive power.
- 2,400 MW under N-G-1 security criteria if the two Huntly Rankine units are available providing only the reactive support.

Post decommissioning of all Huntly Rankine units, the dynamic voltage stability load limits further reduces to around:

- 2,350 MW under N-1 security criteria, and
- 2,100 MW under N-G-1 security criteria.

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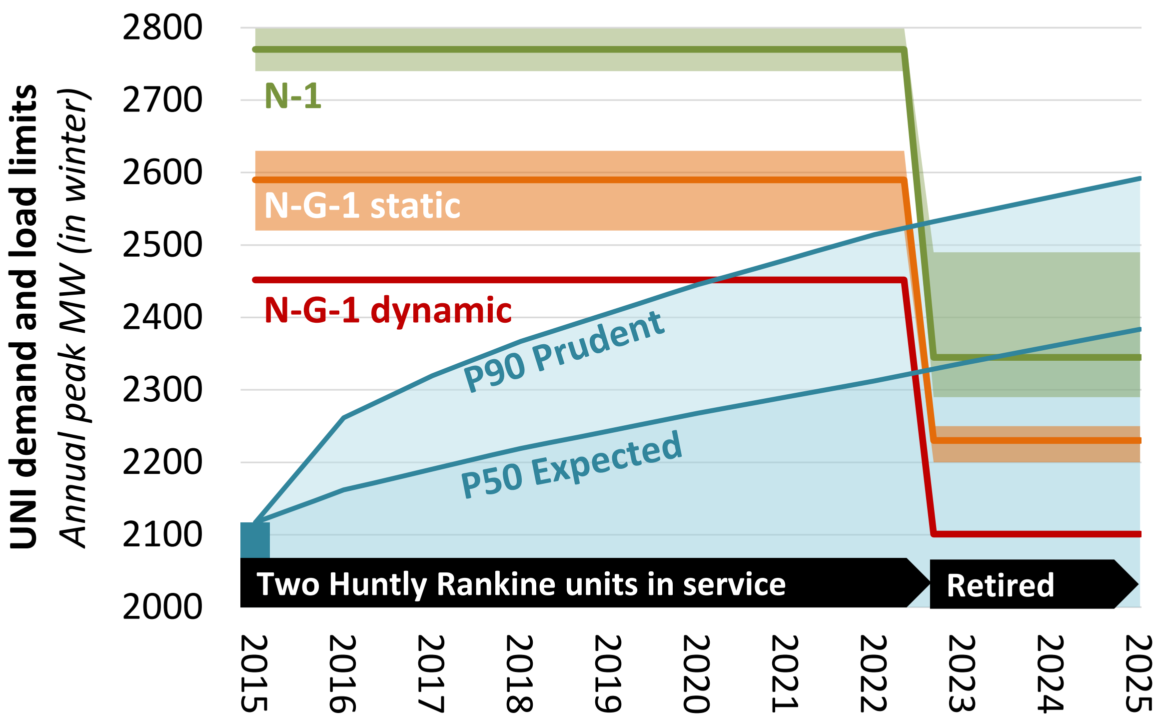
[10] The load limits presented includes a 5% margin in accordance with standard international practice to account for the uncertainties in assumptions.

The above numbers are approximate because they are sensitive to the assumptions, and the system operator may calculate and apply different limits at or closer to real-time.

Figure 3-1 shows the UNI voltage stability load limits plotted along with the 2015 winter peak load and winter prudent peak demand forecast from 2016 to 2025. The worst case outage for:

- N-1 is the loss of a 220 kV Pakuranga–Whakamaru circuit.
- N-G-1 is the loss of a 220 kV Pakuranga–Whakamaru circuit when Huntly unit 5 is not available.

Figure 3-1: Upper North Island forecast annual peak (winter) and voltage stability limits



In Figure 3-1, the:

- N-G-1 dynamic voltage stability limit is as described above
- N-G-1 static voltage stability limit is from the system operator's analysis[11]
- N-1 limit is as described above, also from the system operator's analysis
- Expected (P50) and prudent (P90) forecasts are as presented in section 7.1.1.

[11] From *Upper North Island Operational Limits Following Huntly Rankine unit retirements*, April 2016, available at www.systemoperator.co.nz/activites/current-projects/impact-thermal-generator-decommissioning.

3.5.2 Uncertainty

The N-G-1 static limit and the N-1 limit illustrated in Figure 3-1 included indicative confidence bands indicating the range of uncertainty across three different generation dispatch scenarios, which probably underestimate the actual degree of uncertainty. The N-G-1 dynamic voltage stability limit is represented by a single line because we have not quantified the range of uncertainty in that limit. However, there is likely to be considerable uncertainty, because it is sensitive not only to generation dispatch scenarios but also to motor load assumptions (see section 7.1.3).

The P90 prudent forecast has by design a 10% chance of being exceeded in the first seven years, and does not include allowance for the Electricity Authority's proposed changes to the TPM and ACOT charges which could materially raise peak demand (see section 7.1.2).

There is thus uncertainty in the winter 2021 need date indicated in Figure 3-1: indeed further analysis could indicate that the static N-G-1 voltage stability limit is lower than the N-G-1 dynamic voltage stability limit. We intend to use the N-G-1 dynamic voltage limit binding in winter 2021 as the need date for this project, but be cognisant of the reality that it could change as we further our analysis and as demand trends become clearer.

3.5.3 Need date and quantum

Transpower's analysis indicates that the power system will not be able to supply the peak UNI load from winter 2021 even with two Rankine units available to provide active and reactive power support under the N-G-1 contingent event. The gap between the prudent load forecast and UNI load limit is in the order of 100 MW.

In addition, once the Rankine units retire, there is a much larger gap between the prudent load forecast and the UNI load limit, in the order of 400 MW, and increasing,. Even under the expected forecast the gap is over 200 MW and increasing. This need has to be met before winter 2023.

To meet this need requires either:

- Generation investment at or north of Huntly
- Increased reactive support in the Waikato and/or UNI
- Reduced winter peak load in the UNI.

3.5.4 Voltage support requirement

To reliably supply the UNI peak load without significant local generation creates two issues related to voltage support that must be satisfied:

- Firstly, there must be sufficient reactive power available in steady state in the UNI to enable power to be delivered along the transmission lines from generators south of there. Power flow in overhead transmission lines results in reactive power absorption by the transmission lines, so this reactive power cannot all be provided from the south without creating a significant voltage depression in the UNI.

- Secondly, the dynamic reactive power available must be sufficient to meet all the required contingent events.

To reliably supply the UNI at times of very light load creates the separate issue of the need to reduce the capacitive reactive power (or add sources of inductive reactive power) during steady state operation of the grid. This can be achieved by switching out capacitors, cable circuits and/or lightly loaded overhead transmission lines. The outcome of the static and dynamic voltage investigation within this project will impact the high voltage issue forecasted at light load. We will assess the need to progress an investigation into the high voltage issue once this project reaches a preferred solution.

Question 1	Do you agree with our assessment of need and project scope? Are there any other issues or considerations relating to the need or scope that we should incorporate into this project?

4 Long-list of components

In the absence of significant new generation in the region, a single asset is unlikely to provide a complete economic solution by itself. The preferred solution is expected to be a mix of assets, probably with sequenced introduction. For this reason we are referring to the long-list as a long-list of components, rather than our usual terminology of a long-list of options.

The draft long-list of components is laid out below and summarised in Table 4-1. This draft long-list includes a wide range of possible components for contributing to meeting the need, including both transmission and non-transmission solutions.

The need for investment, described in section 3 above, is such that while there are many components that could contribute to meeting the need for both static and dynamic voltage support, many are quite specific technologies. While the size of the expected need is known, the required size of each component asset in an optimal mix to meet that need is not. Indicative minimum sizes in Mvar are included here to give a lower bound on what is likely to be economic as part of a mix of investments.

While we anticipate that the dynamic voltage stability constraint binds first in the Upper North Island, the poor voltage performance in the Waikato needs to be addressed too. We need static reactive devices in the Waikato, but that does not rule out having dynamic reactive devices there too.

4.1 Reactive power devices

Non-transmission solutions for reactive power devices could be met through a voltage support grid support contract, discussed in section 5.2.

4.1.1 Conventional capacitor banks

Conventional capacitor banks are grid connected and switched with circuit breakers. These are the least expensive form of voltage support but are normally used to provide static voltage support only. However, conventional capacitor banks can be dynamically switched with secondary circuit breakers which could boost reactive power output and speed up voltage recovery.

A capacity per bank of around 50-100 Mvar at high transmission voltage level would likely be appropriate in the Waikato (around Hamilton) or in the UNI regions.

Capacitor banks would require a control system, and would likely be controlled by a reactive power controller.

Shunt capacitors can be connected at distribution level to correct power factors by providing reactive power near the inductive loads that required them, reducing the reactive power drawn from the grid.

Transmission solution	Non-transmission solution
New capacitor(s) at Transpower substation(s)	Embedded in distribution networks, albeit that the Code's requirement for unity power factor would require dispensations to be granted.

Capacitors do not usually provide the fast dynamic response required for sudden power system events when a rapid response (milliseconds) is required to maintain voltage quality. For these events, devices which respond dynamically are required. Generators, synchronous condensers, thyristor switched capacitors (TSCs), static var compensators (SVCs) and static synchronous compensators (STATCOMs) are all examples of such devices.

4.1.2 Fast mechanically switched shunt capacitors and/or CAPS scheme

Both fast mechanically switched shunt capacitors and/or capacitor bank series group shorting (CAPS)[12] schemes are potentially cheaper methods of supplying reactive power dynamically. They are control scheme added to a shunt capacitor bank to switch in the bank or boost additional reactive power capacity from a shunt capacitor bank. The additional reactive power output provides additional temporary voltage support during which corrective actions can be implemented.

Transmission solution	Non-transmission solution
New capacitor(s) at Transpower substation(s)	This solution will not address the issue.

4.1.3 Thyristor switched capacitor banks

Thyristor switched capacitor (TSC) banks are one component of static var compensators (SVC, see below) but can also be installed separately when required. Thyristor switched capacitor banks can respond very rapidly to changes in the power system. The speed of operation is fast enough to provide the dynamic reactive support required, and TSC banks can avoid the discharge requirements of circuit breaker switched capacitors. They will typically require a dedicated transformer.

Transmission solution	Non-transmission solution
New capacitor(s) at Transpower substation(s)	This solution will not address the issue.

[12] The CAPS (capacitor bank series group shorting) scheme was developed by Bonneville Power Administration (BPA) and implemented in its network. This is done by shorting several series groups of capacitor units, which reduces the bank reactance, thereby increasing reactive power output.

4.1.4 Synchronous condensers

A synchronous condenser is akin to a synchronous generation motor whose shaft is not connected but spins freely.

The contribution of a synchronous condenser would vary by location – it would need to be at or north of Huntly. The minimum economic size is likely to be in the tens of Mvars, ideally in the 100-200 Mvar range. They would need to be connected directly to Transpower's high voltage grid assets, embedding them in a distribution network would not meet the need.

Transmission solution	Non-transmission solution
New synchronous condenser(s) at Transpower substation(s)	Conversion of existing generation units (e.g. Southdown or Huntly Rankine units), or new synchronous condenser(s) connected at Transpower substation(s).

Converted generation units could be contracted as a service through a grid support contract, or could be purchased and operated by Transpower.

4.1.5 STATCOM

A static synchronous compensator (STATCOM) is a voltage regulating device based on a power electronics voltage-source converter, and can act as either a source or sink of reactive AC power.

One or more STATCOMs would help, ideally each in the 100-150 Mvar range. For maximum effect they should be located in the Auckland region.

STATCOMs are available up to around 33 kV. These can be grid connected via a transformer, but not embedded in a distribution network.

Transmission solution	Non-transmission solution
New STATCOM(s) at Transpower substation(s)	Reactive support provided from modern wind farms that have STATCOM-like behaviour.

4.1.6 SVC

Static var compensators (SVCs) are also regulating devices based on power electronics and can provide fast-acting reactive power.

SVCs generally require more land area (footprint) for the same sized STATCOM as they have large thyristor controlled reactors and capacitors, and in addition require passive harmonic filters. SVCs can be cheaper than the equivalent STATCOMs, but do not provide as much support at low voltages.

SVCs need to be grid connected via a transformer, and are typically economically viable in the 100 Mvar plus range. For maximum effect they should be located in the Auckland region.

Transmission solution	Non-transmission solution

New SVC(s) at Transpower substation(s)	Reactive support provided from modern wind farms that have SVC-like behaviour.

4.1.7 Hybrid STATCOM/SVC

To provide fast dynamic response over a wider range while minimising both the cost and the land requirements, manufacturers also now offer hybrid STATCOM/SVC solutions which combine the two devices with a single control system.

Transmission solution	Non-transmission solution
New hybrid STATCOM/SVC(s) plant at Transpower substation(s)	Reactive support provided from modern wind farms that have Hybrid STATCOM/SVC-like behaviour.

4.1.8 Hybrid STATCOM/battery

Hybrid STATCOM/battery plant is becoming available that combines the advantages of both (see above and below).

Transmission solution	Non-transmission solution
New hybrid STATCOM/battery plant(s) at Transpower substation(s)	None of which we are aware.

4.1.9 Grid-sized battery storage

Large – multiple tens of MW – batteries, or battery banks or aggregations of that size, could contribute through reducing net demand at peak or contingent times, in a similar manner to demand response. They can also contribute dynamic reactive support.

Like STATCOMs, batteries use DC-AC inverters which may switch off at low voltages, which could be an issue.

Transmission solution	Non-transmission solution
Large grid-sized battery at Transpower substation(s)	Distributed battery storage with appropriate aggregated control system.

4.2 Other transmission assets

This section discusses draft long-list components that are grid assets and that we believe have no non-transmission equivalents.

4.2.1 Series capacitors

Series capacitors are used primarily to obtain the desired load division among parallel lines and to improve system stability. Series capacitors on the Brownhill–Whakamaru (BHL-

WKM) circuits would also improve the dynamic voltage stability in the UNI region (and would reduce transmission losses).

4.2.2 Undergrounding circuits in the Auckland region

Adding cables provides additional capacitance on the network, with experience from the North Auckland and Northland (NAaN) project suggesting that 10 km of cable could provide around 40 Mvars. However, at low load there are limited circuits that can be switched out of service to keep the voltage down, so reactors may need to be added when cables are installed which limits or eliminates the positive benefit of the capacitance at high load. Underground cabling would contribute to the static need only, and is expensive.

4.2.3 New line from generation centre to Auckland

This and the following three options for increasing grid capacity would assist in both static and dynamic voltage support, and in easing thermal transfer limits into the Waikato and Upper North Island.

A new line connecting generation centres from or through the Waikato into Huntly (e.g. from Whakamaru to Huntly) or connecting into the Huntly–Stratford circuits would require a new switching station to decrease impedance and hence improve the flow of Mvars.

4.2.4 Upgrade existing lines to reduce impedance

Impedance in the existing grid south of Huntly could be reduced also through upgrading existing lines, such as duplexing the Otahuhu–Whakamaru circuits or upgrading the existing duplex circuits to triplex or quad.

4.2.5 400 kV conversion

The 220 kV Brownhill–Whakamaru circuits, built under the North Island Grid Upgrade (NIGU) project, are designed to be upgradeable to 400 kV. Series capacitors and more cables would be required as well as 400/220 kV interconnecting transformers.

4.2.6 Grid reconfiguration

Reconfiguring the grid to reduce line length, or better sharing of load between circuits, would reduce voltage drop and assist in meeting the need. One potential option is to build a 220 kV substation east of Hamilton on the Otahuhu–Whakamaru C line.

4.3 System operations

4.3.1 Use dynamic analysis to determine dynamic voltage stability limits operationally

The system operator currently determines static voltage stability limits in real time. It is likely that, following the closure of a number of generating plants in the UNI, the dynamic limit may

be more constraining. Upgrading system operator tools, processes and systems would be necessary to allow the system operator to perform dynamic analysis within operational timeframes.

4.4 Market generation

Additional market generation in Huntly or north would help, both in reducing net MW demand and in providing Mvar support. The minimum economic size is likely to be in the high tens to hundreds of MW.

Market generation has, since market inception[13], been decided upon by the market on a competitive and commercial basis. This remains the preferred means for additional market generation in Huntly or north to occur.

The generation scenarios that we are assuming are described in section 7.2.3. We are especially interested in any information on intentions for new market generation in Huntly or north, which could affect our assumptions and scenarios.

Although pure market-driven investment is preferable, market generation could be contracted under a market generation grid support contract. Transpower's grid support contract product design only allows contracting with market generation under precise conditions, to avoid interfering with the market, as discussed in section 5.4.

Transpower also could build and own generation itself.

Embedded non-market generation is included in demand-side participation below.

Transmission solution	Non-transmission solution
Transpower build and ownership of generation	Market provides (preferred): market generation investment changes our scenarios. Market generation grid support contract.

4.5 Demand-side participation, including embedded generation

Dynamic voltage stability is caused by the re-acceleration of motors immediately after a short circuit fault. To meet the need, the types of loads shed in the demand-side participation (DSP) products for both pre- and post- contingent load shed in sections 4.5.2 to 4.5.4 must contain a high proportion of motor load (rather than resistive load). Reliable embedded non-market generation would also be a contender.

4.5.1 DSP – uncontrolled

Increased uptake – on mass – of emerging technologies including solar photovoltaic (PV), batteries and electric vehicles (EV) can affect both the net MW load and voltage profiles.

[13] Since 1996, other than the brief government procurement and ownership of the Whirinaki power plant.

We have endeavoured to incorporate the effect of such technologies in our demand forecasts and generation scenarios.

4.5.2 DSP – pre-contingent load reduction

Demand response that is called ahead of need based on a forecast could help. This could be called hours ahead of time (as in Transpower's current Demand Response initiative[14]) or closer to real-time, say 15 minutes.

Transpower is currently determining how accurate the forecast would need to be to call demand response with sufficient accuracy to meet the need, which will drive whether pre-contingent demand response is a viable alternative, and if so what call horizon would be adequate, and whether there are other perquisites to its operation, such as:

- an improved medium- or short-term load forecast
- the system operator basing voltage stability constraints on dynamic analysis (section 4.3.1)
- more reliable and resilient communications protocols

4.5.3 DSP – pre-contingent load cap

An alternative to a load reduction product described above is a load capping product that would, for example, limit net load at one or more Auckland GXPs to an agreed amount. Transpower could for example enter a grid support contract with a distribution company or major load to cap its peak load to a certain level under certain conditions, with the counterparty taking responsibility for managing that. An attractive feature of such an approach would be that it could provide some insurance against the potential impact of removing RCPD and ACOT, if that occurred (see section 7.1.2), by in effect rolling those incentives and contracts into the grid support contract framework.

4.5.4 DSP – post-contingent

Alternatively, demand-response could be triggered immediately post-contingency. For a voltage stability issue such as this need, it would have to be on very fast response relays with adequate reliability, security and control: in other words, protection-grade equipment. Such schemes are referred to generically as special protection schemes (SPS). We envisage two options for triggering such a scheme:

- On voltage as 'automatic under voltage load shedding' or AUVLS. Designing and programming a SPS to respond to voltage conditions in the UNI area to drop loads post-contingency can be difficult and challenging as the system instability point could occur at different voltages depending on system conditions.
- On predefined system and operating conditions, which while a proxy for voltage can be easier to implement and monitor.

[14] See the demand response page on Transpower's website for more information.

Question 2	Do you agree with our draft long-list of components? If not, what components should we include or remove?

Table 4-1: Draft long-list summary

Component		Typical duration of construction works[15]	Typical duration of consent process[16,17]	Location	Indicative component size	Transmission solution	Non transmission solution (through GSC)
4.1	Reactive power devices						
4.1.1	Conventional capacitor banks	2-3 years	6 to 18 months	Waikato and/or Upper North Island	~50-100 Mvar	New plant(s) at Transpower substation(s)	Embedded in distribution network, albeit that the Code's requirement for unity power factor would require dispensations to be granted
4.1.2	Fast mechanically switched shunt capacitors and/or CAPS scheme	2-3 years	6 to 18 months		~100 Mvar		This solution will not address the issue
4.1.3	Thyristor switched capacitor banks	2-3 years	6 to 18 months				
4.1.4	Synchronous condensers	3-5 years	6 to 18 months	Huntly or north	~100-200 Mvar		Conversion of existing generation units, or new plant(s) connected at Transpower substation(s)
4.1.5	STATCOM	3-5 years	6 to 18 months	Huntly or north,	~100-150		Reactive support provided from

[15] The typical duration of construction works includes design, procurement and construction time for the discrete component only and is not site specific. It does not include enabling activities such as support infrastructure, designations, property or consents, the durations of which are highly site specific and may be significant. Most development plans will include multiple components from Table 4-1.

[16] It could take several years to obtain the required consents for components that require work outside Transpower's existing sites. There is significant uncertainty in any estimate of the duration of the consent process as it is highly sensitive to the particular route chosen and the scale of work and access required.

[17] While some design and procurement work can be undertaken in parallel with the consent process, we consider the total delivery time to be approximately the duration of construction works plus the duration of the consenting process.

Component		Typical duration of construction works[15]	Typical duration of consent process[16,17]	Location	Indicative component size	Transmission solution	Non transmission solution (through GSC)
4.1.6	SVC	3-5 years	6 to 18 months	most effective in the Auckland region	Mvar		modern wind farms that can behave similarly to reactive power devices
4.1.7	Hybrid STATCOM/SVC	3-5 years	6 to 18 months				
4.1.8	Hybrid STATCOM/battery	4-6 years	6 to 18 months				None of which we are aware
4.1.9	Battery storage	4-6 years	6 to 18 months		Multiple tens of MW		Distributed battery storage with appropriate aggregated control system
4.2	Other transmission assets						
4.2.1	Series capacitors	3-5 years	6 to 18 months	BHL-WKM circuits		Transpower owned in Transpower substation	n/a
4.2.2	Undergrounding circuits	3-5 years	5 to 7 years	Auckland region		Transpower asset	
4.2.3	New line	4-5 years	5 to 7 years	Generation centre to Auckland			
4.2.4	Upgrade existing lines to reduce impedance	2-3 years	3 to 4 years	South of Huntly			
4.2.5	400 kV conversion	3-5 years	3 to 4 years	BHL-WKM line			
4.2.6	Grid reconfiguration	2-5 years	N/A	East of Hamilton			
4.3	System operation						
4.3.1	Use dynamic analysis to determine dynamic voltage stability limits	N/A	N/A	North Island	n/a	SO applies voltage stability limit based on dynamic analysis	n/a
4.4	Market generation						

Component		Typical duration of construction works[15]	Typical duration of consent process[16,17]	Location	Indicative component size	Transmission solution	Non transmission solution (through GSC)
4.4	Market generation	N/A	N/A	Huntly or north	High 10's to 100's of MW	Transpower build and ownership of generation	Market provides (preferred): market generation investment changes our scenarios Market generation GSC
4.5	Demand-side participation, including embedded generation						
4.5.1	DSP – uncontrolled	N/A	N/A	Upper North Island	See Appendix G	No identified transmission equivalents	Market evolution e.g. PV, EV
4.5.2	DSP – pre-contingent load reduction	N/A	N/A				Load reduction service coupled with accurate load forecast
4.5.3	DSP – pre-contingent load cap	N/A	N/A				Load capping, e.g. Auckland GXP net load < X
4.5.4	DSP – post-contingent	N/A	N/A				Special Protection Scheme

5 Invitation for information on non-transmission solutions

As well as a vehicle for consulting on our draft long-list and assumptions, this document also serves to invite interested persons to provide views or information on or relevant to possible non-transmission solutions to meet the need.

A non-transmission solution is any way of solving the need without investing in transmission assets. We can fund a single non-transmission solution, a combination of non-transmission solutions, or a combination of transmission and non-transmission solutions if they prove to be the most economical solution to meet the need.

We are interested in all non-transmission solutions, including:

- voltage support
- demand side participation including non-market generation
- market generation

Section 4 presents our draft long-list of components, including non-transmission solutions. We invite you to suggest other non-transmission solutions that we have missed, or to provide more information on those non-transmission solutions that we have included. Section 5.5 below lists some specific types of information on non-transmission solutions that would help us assess their technical and economic suitability in meeting the need.

Sections 5.1 to 5.4 describe our grid support (GSC) product, which is the mechanism by which Transpower could contract for non-transmission solutions.

5.1 Transpower's grid support contract (GSC) product

Transpower has a grid support contract (GSC) product suite that encompasses voltage support, demand side participation including non-market generation (with both pre- and post-contingent, and both load reduction and load capping products), and market generation.

Transpower's GSC product suite was launched in 2010. Since then, we have made considerable progress in testing, refining and simplifying our approach to pre-contingent load reduction through demand side participation, under Transpower's Demand Response programme. However we have not had to enter into GSCs for voltage support or market generation, nor for post-contingent or load capping demand side participation products (all of which could be viable components in meeting the need of this project).

For that reason we have refreshed our GSC product suite to incorporate learnings through our Demand Response programme, the change of investment approval regime from the Electricity Commission to the Commerce Commission, and a general update and refresh. The fundamental design principles have not changed.

All parties considering responding to this invitation for information on non-transmission solutions are encouraged to familiarise themselves with Transpower's GSC product design, the details of which are available at www.transpower.co.nz/grid-support-contracts. A list of the GSC design features is included for ease of reference in Appendix I. The following sections provide further summary and some information specific to this project.

5.2 GSCs for voltage support

As discussed in section 4 above on the draft long-list, many reactive power devices are available as transmission assets, which Transpower could build and own. However, many are available as non-transmission solutions that Transpower could contract for through a voltage support GSC. We have included our views on these in the draft long-list, and invite you to consider whether we have missed any.

The benefit obtained from such voltage support depends on its size and technology, its location in the network, the connecting voltage and the extent of voltage support already on the network.

As a general rule of thumb, the UNI load limit will be increased by approximately 1.3 MW for every 1 Mvar of dynamic reactive power capability added at Silverdale. To assist in understanding the variation with location, we show the relative benefit of connecting a +/- 60 Mvar device at different locations and voltage levels in Table 5-1. We chose Silverdale as the reference because it is one of the locations with the greatest benefit to the UNI load limit.

Table 5-1: The relative benefit of connecting a device to different locations and voltages levels in the UNI and Waikato areas

Connection point (+/- 60 Mvar)	Benefit to the UNI load limit (MW)	Relative benefit (%) (referenced to Silverdale)
Silverdale (33 kV)	80	100%
Henderson (33 kV)	80	100%
Pakuranga (33 kV)	75	94%
Mount Roskill (22 kV)	75	94%
Ohinewai (220 kV)	75	94%
Bombay (33 kV)	75	94%
Bream Bay (33 kV)	70	88%
Hamilton (33 kV)	70	88%
Waihou (33 kV)	60	75%
Waikino (33 kV)	10	13%

As shown in the table, connecting the reactive devices in the Auckland region generally gives greater benefit of var injection. The further the device is embedded in the Waikato region, the less effective the device for voltage support.

5.3 GSCs for demand side participation including non-market generation

We could enter into GSCs for demand side participation, including non-market generation. Such non-transmission solutions could be pre- or post-contingent, and could be load capping or load reduction products.

Transpower's Demand Response programme has to date focused on load reduction called usually two to three hours ahead of need, using the system operator's medium-term load forecast to predict when load limits might otherwise be met.

For thermal limits, we generally operate the system with 15 minute offload times: the system operator has that long to re-dispatch or invoke other measures to resolve the issue, so at its worst the resolution is likely to be calls for localised load reduction.

However, the primary need discussed here is dynamic voltage stability. This can happen very quickly – in seconds – and the consequences can be severe, at the extreme a full grid collapse in the Upper North Island, possibly extending southwards across the North Island. Not only could the event be widespread, but also prolonged, with the grid being gradually re-energised using the black start ancillary service.

For pre-contingent products, Transpower would use dynamic voltage stability limits to forecast when the demand-side participation needs to be called as part of the system operator's normal function. There are two interrelated issues here:

- The system operator does not currently have the ability to determine dynamic voltage stability limits using dynamic analysis in or approaching real-time. Rather it uses static analysis. As the critical risk is a dynamic rather than static issue, this creates a significant risk.
- The system operator's medium-term load forecast is not accurate enough to call demand response hours ahead of time without significant risk of not making a call when, in hindsight, a call should have been made. This risk can be mitigated to a degree by reducing the call horizon, say to 30 minutes or into the sub-30 minutes domain of the system operator's short-term load forecast, say 15 minutes. This would likely influence the types of load and communications that would be most appropriate.

As noted in section 4.5, the types of loads shed pre- and post- contingency must contain a high proportion of motor load (rather than resistive load). Reliable embedded non-market generation would be a contender.

Types of GSC product for demand side participation, including non-market generation, that we have not used to date but might be appropriate to the need of this project include post-contingent or load capping demand side participation products. Examples of such products are included in the draft long-list (sections 4.5.2 to 4.5.4), and we ask you to consider whether we have missed any.

Forecast call profiles for demand-side participation are included in Appendix G.

We invest based on a prudent forecast, and our non-transmission solution requirements will be determined by a prudent forecast. Under the forecast assumed here, this means approximately 24 MW of demand response is required in the first year (winter 2021), increasing to approximately 59 MW for the second year (pre decommissioning of the remaining Huntly Rankine units).

The contract term for a non-transmission solution will be determined by the amount of net load reduction that can be provided. For instance if we could secure in excess of (currently) 59 MW net load reduction over two years at a lower cost than the equivalent capital investment, we would consider a two year contract.

While we invest to meet a prudent forecast, the expected level of demand is lower. There is uncertainty over the level and profile of demand in 2021 and beyond, but in Appendix G we have attempted to provide some information about the number of calls that demand-side participation providers could expect based on either an expected or prudent level of growth. That is currently none for the expected forecast pre-2023.

5.4 GSCs for market generation

For reasons of avoiding interference in the highly competitive market for generation investment and operation, Transpower has very stringent criteria for considering GSCs for market generation. These reasons are explained in the GSC design document on the website referenced above.

Essentially, GSCs could be offered to market generators to modify their plans to meet Transpower's need for capacity, reliability, timing and location. For example, if a generator commits to commissioning a plant at or north of Huntly two years after the need date, we would consider a GSC to bring the commissioning forward, if possible.

We are extremely interested in any information on plans for generation investment, especially at or north of Huntly. Such information would inform our scenarios, but some could qualify for consideration of a market generation GSC too.

5.5 Non-transmission solution information sought

Transpower can fund a single non-transmission solution or a combination of solutions if they prove to be the most economical solution to an identified need. Non-transmission solutions can either reduce the UNI winter peak demand (ensuring that it remains below the load limit) or increased reactive support to increase the UNI load limit.

We intend to use your response not only to finalise the long-list, but also to guide our short-listing of long-list components. For that purpose we invite information on specific non-transmission solutions relevant to the high-level application of our reliability, good electricity industry practice (GEIP) and economic criteria. Ideally this would include as a minimum:

- your full contact details.
- whether you are a registered market participant (not required for all GSCs).
- describe how the reliability of your non-transmission solution will be delivered.

- sufficient technical detail to enable an assessment of the component(s), especially its reliability.
- in the case of load reduction solutions, the nature of the motor load.
- indicative cost and price information, ideally as an expected cost with an upper and lower bound.
- the size of the non-transmission solution, both current and projected.
- the (potential) connection point(s), including connection voltage, of the options.
- the construction and commissioning timetable for any not-yet-commissioned plant.
- the times the component would be available.
- how far ahead of first use it would be appropriate to contract for your non-transmission solution.
- how long you would require to respond to a request for proposals if we sought more detailed information. Note that we consider six weeks the minimum requirement but acknowledge that longer may be needed.

Question 3	This document serves as an invitation to provide information on non-transmission solutions. Any submission on this aspect should provide as much detail on the non-transmission solution as possible. Do you have any suggestions or proposals for non-transmission solutions to meet the need? If so, please provide the information requested (in section 5.5) so that we can apply a high-level assessment against our short-listing criteria.

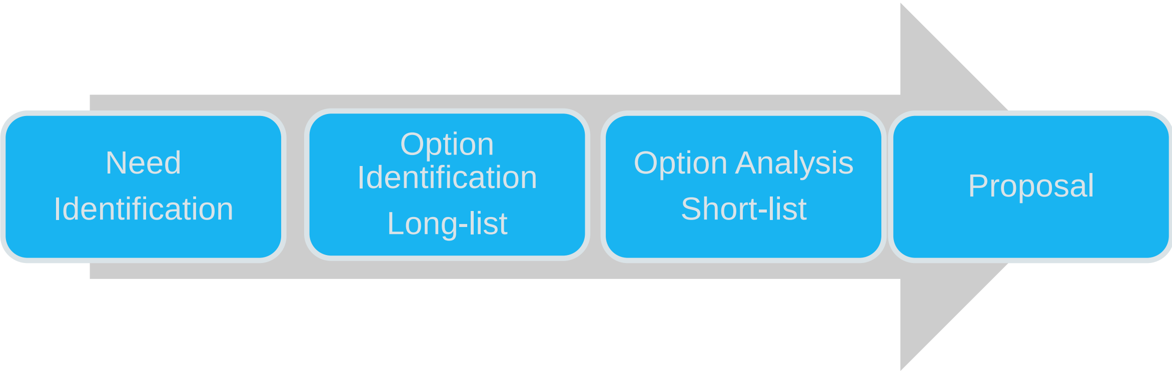
Transpower would contract with any selected non-transmission solutions in accordance with its prevailing GSC product design (available at www.transpower.co.nz/grid-support-contracts, with the key design features summarised in Appendix I). Feedback on or suggestions for improving that design are always welcome.

Question 4	Do you have any suggestions for enhancing Transpower's grid support contract (GSC) product design? If so, please provide your reasons, based on the rationale provided in our GSC design features document at www.transpower.co.nz/grid-support-contracts

6 Developing an investment proposal

6.1 Project process

The diagram below illustrates the general investment project process that is being followed for this project.



Transpower's investment planning process is described on its website[18]. The following sections describe where this consultation document fits into this process.

6.1.1 Need identification

The need identification is presented in section 3. We invite feedback on the need.

6.1.2 Option identification

We are currently engaged in option identification (albeit using the terminology of components rather than options, as described above).

Our draft long-list of components is presented in section 4. We invite feedback on the long-list, especially with regard to non-transmission solutions.

Once we have received your feedback, we will finalise the long-list, which is the end of the option identification stage.

6.1.3 Option analysis

We propose to evaluate the long-list of components using a set of high-level screening criteria. The screening criteria will be used to eliminate those components that are not appropriate for consideration in the short-list of components and to which we apply the Investment Test.

[18] See www.transpower.co.nz/about-us/our-purpose-values-and-people/planning-future-0

We intend to use five criteria for screening:

- Fit for purpose
- Technical feasibility
- Good electricity industry practice (GEIP)
- System security (additional benefit resulting from an economic investment)
- Indicative cost

The short-listing criteria are detailed in Appendix B.

Question 5	Do you agree with our criteria for short-listing? If not, what criteria should we modify, include or remove, and why?

If appropriate non-transmission solutions are identified, more detailed information will be requested as required.

We will construct a range of development plans – sets of components with size, location and commissioning time – that meet the need.

The next stage is applying the Investment Test – as defined in the Capex Input Methodology – to the development plans to select our preferred development plan. The development plans extend out decades, and we will decide how much of the early years of the development plan become our proposal.

The preferred option is the development plan which maximises net electricity market benefit while accounting for unquantified costs and benefits. The Investment Test requires Transpower to consider unquantified costs and benefits when the difference in quantified net electricity market benefit is small relative to the cost of the project. Costs and benefits can be considered unquantified if the magnitude is small relative to the cost to calculate it, or the expected magnitude cannot be calculated with an appropriate level of certainty.

The assumptions that we intend to use for our option analysis are laid out in section 7. We invite feedback on these assumptions.

6.2 Options for approval and funding

Transpower has three possible avenues for funding voltage management investments in the Waikato and Upper North Island.

6.2.1 Major Capex Proposals (MCP)

Grid enhancement projects costing over $20 million (unless covered by an approved GUP) require Commerce Commission approval. These proposals are submitted in the form of

Major Capex Proposals (MCPs). The Commerce Commission reviews MCPs by applying the Capital Expenditure Input Methodology Determination (CapexIM)[19].

The CapexIM requires us to follow certain processes and to apply the Investment Test (a market cost-benefit test).

6.2.2 UNIDRS GUP amendment

The Upper North Island Dynamic Reactive Support (UNIDRS) project was approved as a Grid Upgrade Plan (GUP) by the former Electricity Commission[20].

UNIDRS assumed that all existing generation would remain in operation until the end of the analysis period, 2030. With the benefit of hindsight over the thermal decommissionings, these generation scenarios were optimistic. Had we used the latest scenarios, the need for voltage support within the Upper North Island would have increased significantly.

Transpower's view is that it may be appropriate to fund some or all of the assets required to meet the need, in particular any dynamic reactive devices in the Upper North Island, through the UNIDRS project. Transpower would need to apply to the Commerce Commission for approval of an amendment to the approved major capex project outputs and timing for the UNIDRS GUP.

6.2.3 Base capex or opex

If the preferred solution (less any components that can be covered by a UNIDRS GUP amendment) amounts to less than $20 million then they could be funded from Transpower's base capex under RCP2, which covers 2015-2020, or RCP3, which takes effect from July 2020.

[19] http://www.comcom.govt.nz/transpower-input-methodologies/

[20] http://archive.electricitycommission.govt.nz/archive.electricitycommission.govt.nz/opdev/transmis/gup/2009GUP/uni.html

7 Option analysis – Assumptions

7.1 Demand assumptions

7.1.1 Demand growth assumptions

Transpower has recently completed its annual update of its demand forecasts and plans to use these to assess the need date and the economic benefits of our short-listed investment options.

The need date is assessed using the prudent demand forecast and economic benefits are modelled using the expected forecast. See section 2.4 for an explanation of expected and prudent peak demand forecasts.

The Upper North Island and Waikato prudent and expected peak demand forecasts are listed in Table 7-1 and more detailed information is available in Appendices C-F.

Table 7-1: Upper North Island and Waikato prudent and expected demand forecasts

Year	Expected Winter peak demand (MW)		Prudent Winter peak demand (MW)	
	Upper North Island	Waikato	Upper North Island	Waikato
2016	2159	510	2260	526
2017	2188	519	2318	539
2018	2218	527	2366	550
2019	2243	536	2406	562
2020	2265	544	2442	573
2021	2288	553	2477	584
2022	2311	561	2511	596
2023	2335	570	2537	604
2024	2358	579	2562	614
2025	2383	587	2589	623
2026	2407	597	2616	633
2027	2430	607	2641	644
2028	2454	616	2667	654
2029	2478	626	2693	664
2030	2502	635	2720	674

In additional to underlying demand growth, we will consider a number of levels of electric vehicle uptake. Electrification of transport has significant potential to reduce national carbon emissions but will increase electricity demand.

Table 7-2 contains the three levels of additional energy load from electric vehicles we will consider. Note that each level of electric vehicle uptake is associated with one or more generation scenarios discussed in section 7.2.3.

Table 7-2: Growth in annual energy demand due to electrification of transport - GWh

	Low	Medium	High
Relevant Generation scenario	Scenarios 1, 2, 3	Scenario 4	Scenario 5
2020	5	44	63
2025	20	177	406
2035	84	752	2683
2045	199	1776	5125

We have not included retirement of the aluminium smelter at Tiwai Point in our base scenarios as it does not materially affect the Upper North Island load limit presented in section 3.5. The load limit is driven by load in the Waikato and Upper North Island, so a load reduction at Tiwai Point does not change the restriction on import into Auckland and Northland.

However, closure of the smelter could bring forward the retirement of the remaining Rankine units and therefore the need date for investment.

We will address this risk and the economic impact of the smelter retirement on investment options by including a sensitivity with the smelter shutting down.

A sensitivity is an additional demand or generation future that is not included in the base scenarios. This approach allows us to test specific critical uncertainties that could confound the analysis if included in the base set of scenarios.

We will also conduct high and low demand sensitivities to test the impact of uncertainties in our demand forecast.

Question 6	Do you think that the demand growth assumptions are appropriate for this project? If not, how could we improve them?

7.1.2 Implications of TPM and DGPP changes

The Electricity Authority released in May 2016 its proposals for changes to the transmission pricing methodology (TPM) and the distributed generation pricing principles (DGPP)[21,22]. Amongst other changes, the Electricity Authority is proposing to remove the current Regional Coincident Peak Demand (RCPD) charge from the TPM and remove the regulated pricing principle for distributed generation (which means that distributors currently paying the generators can no longer recover the costs from consumers).

[21] Schedules 12.4 and 6.4 of Code respectively.

[22] See www.ea.govt.nz/development/work-programme/transmission-distribution/transmission-pricing-review/

At present, distributors can reduce their transmission charges through management of their net load at RCPD times, by both

- network management (eg through use of ripple control)
- contracting with local embedded generation to run at peak times, assisted by the avoided cost of transmission (ACOT) payment mechanism.

The Electricity Authority proposes to:

- remove the DGPP for the Lower North Island and Lower South Island in April 2017
- remove the DGPP for the Upper North Island and Upper South Island in April 2018
- have a new TPM with no RCPD (peak) charges by April 2019.

These two changes may reduce network and local generation response to peak demand and hence raise net peak demand. We have not included the potential impact of this in our peak demand forecasts, as we currently have little information on the expected scale of the problem. We are interested in your views on the expected impact of these policy changes, especially on winter demand peaks in the Upper North Island.

Question 7	Do you think that, if the proposed removal of the DGPP and the RCPD charge from the TPM occur, net peak demand in the Upper North Island will be affected? If so, by how much?

7.1.3 Motor load assumptions

The load model determines, using dynamic analysis, how the load reacts to faults and dips in voltages. As explained in section 3.5, the calculation of the dynamic voltage stability limit, and hence the need date, is sensitive to the assumptions of the load model.

A motor load data survey was carried out for the Upper North Island by Sinclair Knight Merz (SKM) in 2013. The survey was done for the peak winter period and the extreme summer period, and the findings of the former form a basis for our analysis. This is used for the Upper North Island load model in our analysis. The load composition for the entire Upper North Island is summarised in Table 7-3.

We have not yet carried out a motor load survey in the Waikato region, so we have assumed the same average load composition for the Waikato load, as given in Table 7-3.

Table 7-3: Upper North Island and Waikato load composition summary

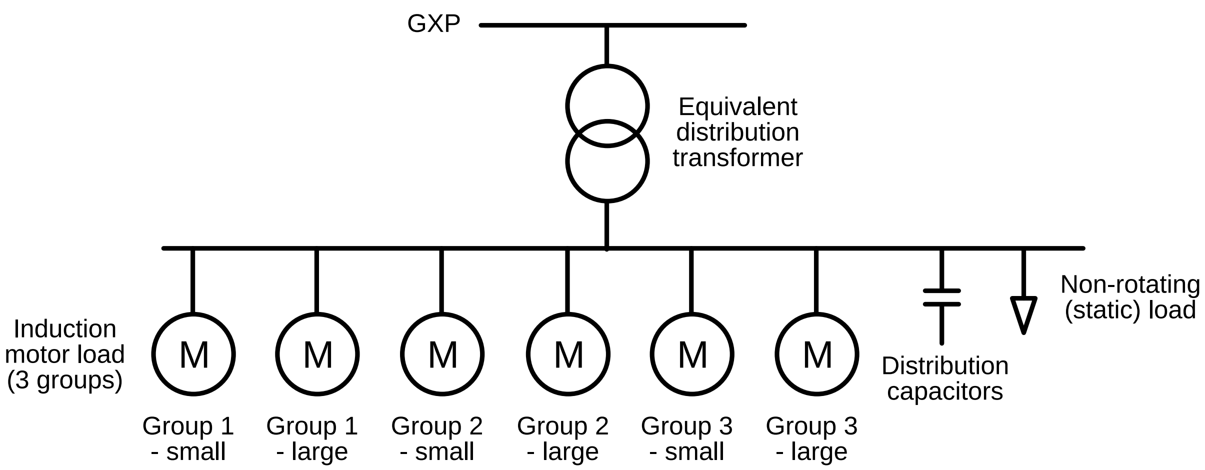
Period	Static	Induction motors					
		Group 1		Group 2		Group 3	
		Large	Small	Large	Small	Large	Small
Summer GXP average	50%	6.3%	18.3%	1.4%	13.4%	2.8%	7.8%
Winter GXP average	59.6%	5.1%	14.5%	1.2%	11.8%	2.2%	5.6%

For the purposes of this project, it is assumed that these motor load percentages do not change over time. Sensitivity analysis will be undertaken to test the importance of this assumption on the outcome of the analysis.

Figure 7-1 shows the load composition at each grid exit point. The distribution network is modelled as a transformer between the grid exit point and the load, with an assumed 10% network impedance. The load model consists of:

- induction motor load. The motors are split into three groups according to how they might respond, and what their effect might be on dynamic voltage stability following a contingent event. Each group was further subdivided by motor sizes (large and small[23]).
- static “non-rotating” load. This load is assumed to stay connected during the fault
- known distribution capacitors. These capacitor banks are needed to support voltage in the distribution network and meet distribution companies’ power factor obligations.

Figure 7-1: Load model, modelled at each Upper North Island and Waikato grid exit point



Transpower is working to improve its motor load composition, and welcomes any information that you can provide to assist us in this.

Question 8	Do you have any more detailed motor load information for the Upper North Island and Waikato that would allow us to improve our modelling?

7.2 Generation and dynamic reactive support assumptions

7.2.1 Existing generation

We assume that, with the exception of the Huntly Rankine units which retired by the end of 2022, the existing generation in the Upper North Island will continue to be connected to the

[23] Large motors are those with ratings greater than 150 kW.

grid for the duration of the analysis period. Table 7-4 lists the existing generation assumed for this project.

Table 7-4: Existing UNI generation

UNI Generation	Capacity	Dispatch P	Dispatch Q (+ve capacitive range, -ve inductive range)
Glenbrook	112 MW	77 MW	0 Mvar
Ngawha	25 MW	25 MW	0 Mvar
Huntly			
Rankine (U1 and U2)*	500 MW	500 MW	+242/-44 Mvar
CCGT (U5)	400 MW	400 MW	+202/-133 Mvar
GT (U6)	50 MW	40 MW	+38/-18 Mvar

* The project will assume that Huntly Rankine units 1 and 2 will be retired by the end of 2022. The Otahuhu combined cycle (OTC) has been decommissioned, as has Southdown.

Question 9 Are you aware of any other existing generation in the UNI that we should include in our analysis?

7.2.2 Dynamic reactive support

Table 7-5 shows the existing and planned dynamic reactive support we propose to assume for this project.

Table 7-5: Dynamic reactive support

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

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 reactive reserve to respond to the system events.

Question 10 Are you aware of any other dynamic reactive support sources that we should assume?

7.2.3 Generation scenarios

The Investment Test, set out in the CapexIM, requires that we consider market development scenarios in our analysis. Using market development scenarios ensures that our economic analysis is robust to the uncertainty around generation expansion and load growth. A market development scenario is an internally consistent set of input assumptions that

represents a plausible future of the electricity system which then drives the rate, location and type generation expansion.

These assumptions include:

- demand growth
- capital costs for different generation technologies
- resource availability
- fuel and carbon costs
- penetration of electric vehicles
- uptake of emerging technologies such as solar photovoltaics (PV) and distributed energy storage

For this consultation we have constructed generation build schedules based on the Ministry of Business, Innovation and Employment's (MBIE's) draft Electricity Demand and Generation Scenarios (EDGS) and the Smart Grid Forum's Disruptive Technology scenario [24,25]. The draft EDGS was released in May 2015 and presented eight scenarios summarised below. The Smart Grid Forum was commissioned by MBIE and the Electricity Networks Associated to facilitate information sharing and dialogue about the impact of emerging technologies on electricity distribution.

The scenarios presented in the draft EDGS were:

- Scenario 1: Base case (Mixed Renewables)
- Scenario 2: High Geothermal Access
- Scenario 3: Low-cost Fossil Fuels
- Scenario 4: Global Low Carbon Emissions
- Plus four demand scenarios based on Scenario 1
    - Scenario 1 with High Growth
    - Scenario 1 with Low Growth
    - Scenario 1 with Tiwai Off
    - Scenario 1 with Tiwai at 400 MW

We intend to use scenarios 1 to 4 and undertake sensitivity analysis on demand growth and retirement of the aluminium smelter as discussed in section 7.1.1. We consider this a more effective approach than including these uncertainties in our base scenarios.

Our final scenario – Scenario 5 – uses solar PV and electric vehicle growth based on the Smart Grid Forum's Disruptive Technologies scenario and uses the other assumptions from Scenario 1. See section 7.1.1 for details on electric vehicle energy load growth and Figure 7-2 below for solar PV uptake assumptions.

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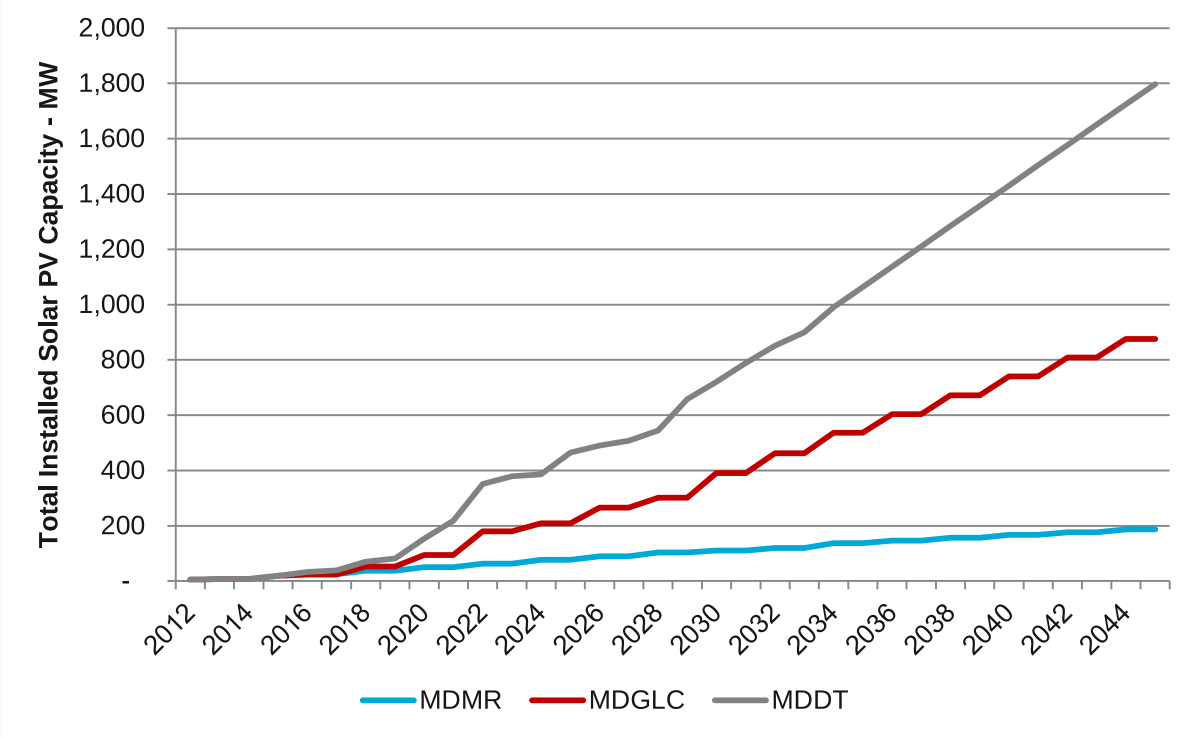
[24] www.mbie.govt.nz/info-services/sectors-industries/energy/energy-data-modelling/modelling/electricity-demand-and-generation-scenarios/draft-edgs-2015

[25] /www.mbie.govt.nz/info-services/sectors-industries/energy/electricity-market/nz-smart-grid-forum

Figure 7-2: National solar photovoltaic installed capacity scenarios



Generation expansion other than solar has been modelled using the Electricity Authority's Generation Expansion model (GEM). GEM produces a least-cost build schedule based on demand, future generation plant, fuel and carbon costs, and network assumptions.

We intend to review the scenarios in this consultation in light of the final EDGS scenarios. We understand that MBIE may soon publish a final EDGS that will replace the 2010 Statement of Opportunities (2010 SoO) as the default scenarios to consider with applying the Investment Test under the CapexIM.

With the removal of more than 500 MW of Upper North Island generation and an additional 500 MW at risk if the Rankine units at Huntly retire, the critical assumption for this project is the location of replacement generation. If significant new generation appears in, or north of, Auckland then the need for voltage management in the UNI in the medium term could ease significantly or even vanish. However, we are unaware of significant generation investment planned in the Upper North Island area.

Table 7-6 shows the changes in generation capacity in this region of interest in our current base scenarios. Note that build schedules in Scenarios 1 to 4 have been updated from those published in the draft EDGS to reflect more recent announcements and ensure enough diversity between the scenarios to test the investment options.

Appendix H provides the full build schedules associated with each of our base scenarios.

Table 7-6: Waikato and Upper North Island build schedules by scenario

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Solar PV scenario	Low	Low	Low	Medium	High
Electric vehicle scenario	Low	Low	Low	Medium	High
2019	Whakamaru Upgrade (20MW)	Whakamaru Upgrade (20MW)	Whakamaru Upgrade (20MW)	Whakamaru Upgrade (20MW)	Whakamaru Upgrade (20MW)
	New Waikato Gas Peaker (200 MW)				New Waikato Gas Peaker (200 MW)
2020	Ngawha geothermal expansion (25 MW)	Ngawha geothermal expansion (25 MW)			Ngawha geothermal expansion (25 MW)
2022				Taharoa Wind (54 MW)	Gas Cogen (40 MW)
2023	Rankine Units Retire (-500MW)	Rankine Units Retire (-500MW)	Rankine Units Retire (-500MW)	Rankine Units Retire (-500MW)	Rankine Units Retire (-500MW)
	New Huntly CCGT (475 MW)				
2026	Hauauru ma raki Wind stage 1 (250 MW)				
2029	Huntly unit 6 retires (-51 MW)				
2032					Ngawha Expansion stage two (25 MW)
2035			New Huntly CCGT (475 MW)		
2036				Hauauru ma raki Wind stage 1 (250 MW)	
2042					Mangakino Geothermal (40 MW)
2043	Ngawha Expansion stage two (25 MW)			Mangakino Geothermal (40 MW)	
2044					New Huntly CCGT (475 MW)
2045	Taharoa Wind (54 MW)	Taharoa Wind (54 MW)		Kaipara Tidal (60 MW)	

It is also important that we ensure that the scenarios show diversity in the location of new generation capacity south of Waikato to ensure that our analysis is robust. We have modified each scenario in order to ensure that there is sufficient locational diversity such that the five scenarios assume new generation is focused in one of the following regions:

- **Scenario 1 (Mixed Renewables): Waikato and Upper North Island:** The remaining Rankine units are replaced with similar capacity at Huntly or further north (or stay in service).
- **Scenario 2 (High Geothermal Access): Bay of Plenty:** The remaining Rankine units retire in 2022 and generation expansion is focussed in the Bay of Plenty
- **Scenario 3 (Low-cost Fossil Fuels): Taranaki:** The remaining Rankine units retire in 2022 and generation expansion is focussed in Taranaki
- **Scenario 4 (Global Low Carbon Emissions): Lower North Island and South Island:** The remaining Rankine units retire in 2022 and generation expansion is focussed to the south of Bunnythorpe
- **Scenario 5 (Disruptive Technologies): Central North Island:** The remaining Rankine units retire in 2022 and generation expansion is focussed in the region between Bunnythorpe and Wairakei.

As indicated above, we may need to update the scenario assumptions and generation build schedules presented in this document following the release of the EDGS or as new information becomes available. Significant changes to the scenarios input assumptions could alter the merit order of new investment. We will include feedback from this consultation in the scenarios we use in further analysis, and continue to monitor news from the industry.

If we were to adopt the final EDGS scenarios we would look to modify them in a similar way to above to ensure there was enough diversity in the location of generation to adequately test the development plans. This investment need is very sensitive to the location of new generation so sufficient diversity between the scenarios is important. We do not envisage changing the other input assumptions such as fuel costs and technology change as they are central to the story of the scenario.

Feedback on these modifications to the EDGS scenarios is welcomed.

Table 7-7 includes generation plant that have been proposed or consented according to Electricity Authority data. We welcome any feedback on this list of plant, the associated specifications and the likelihood of projects proceeding.

Table 7-7: Proposed or consented generation plant by region

Plant	Technology	Capacity (MW)	Status	Earliest Commissioning Date
Huntly and north				
Awhitu	Wind	18	Consented	2016-2020
Ngawha expansion	Geothermal	50	Consented	2017-2020
Kaipara Harbour pilot	Tidal	200	Consented	2017-2020
Taharoa	Wind	54	Consented	2017-2020

Plant	Technology	Capacity (MW)	Status	Earliest Commissioning Date
Bay of Plenty				
Rotoma	Geothermal	35	Applied for consent	2017-2020
Te Ahi O Maui	Geothermal	27	Under Construction	2018
Taranaki				
Junction Road	Gas Peaker	100	Consented	2016-2020
Waverley Wind Farm	Wind	130	Applied for consent	2020
Lower North Island and South Island				
Belfast	Diesel	11.5	Consented	2017-2020
Bromley	Diesel	11.5	Consented	2017-2020
Rakaia River	Hydro	16	Consented	2017-2020
Lake Pukaki	Hydro	35	Consented	2017-2020
North Bank Tunnel	Hydro	200-280	Applied for consent	2017-2020
Balmoral Hydro	Hydro	15	Applied for consent	2017-2020
Wairau	Hydro	70.5	Consented	2017-2020
Hawea Control Gate Retrofit	Hydro	17	Consented	2017-2020
Stockton Plateau	Hydro	25	Consented	2017-2020
Stockton Mine	Hydro	35	Consented	2017-2020
Arnold (Dobson)	Hydro	46	Consented	2017-2020
Mt Cass	Wind	41-69	Consented	2017-2020
Hurunui	Wind	76	Consented	2017-2020
Central Wind (Moawhango)	Wind	120-130	Consented	2017-2020
Turitea	Wind	303	Consented	2017-2020
Mahinerangi Stage 2	Wind	164	Consented	2017-2020
Kaiwera Downs	Wind	240	Consented	2017-2020
Castle Hill	Wind	860	Consented	2017-2020
Puketoi	Wind	159	Consented	2017-2020
Long Gully	Wind	12.5	Consented	2017-2020
Upper Fraser	Hydro	6.5	Consented	2020
Central North Island				
Ruataniwha Plains	Hydro	6.5	Consent under appeal	2017-2020
Waitahora	Wind	156	Consented	2017-2020
Maungaharuru	Wind	270	Consented	2017-2020
Taumatatorara	Wind	44	Consented	2017-2020
Tauhara II	Geothermal	250	Consented	2020

Question 11	Do you think that the generation scenarios are appropriate for this project? If not, how could we improve them, especially with regard to our assumptions on generation that will be built at or north of Huntly?

7.2.4 Limits of reactive support

There will inevitably be a limit to how much we can 'prop up' the voltage in the UNI through using more and more reactive support devices. Eventually, we will need more generation at Huntly or north, or more transmission capacity south of Huntly (to reduce impedance).

Currently we do not know what that limit is. We will be analysing this issue as part of this project: we currently expect the limit to be reached within the 2045 analysis period (see section 7.3.1 below). We therefore anticipate that, once we ascertain an appropriate limit, we may have to modify our generation scenarios or future transmission grid to introduce more generation or transmission capacity by then.

7.3 Investment Test parameters

7.3.1 Analysis period

The calculation period of the Investment Test is specified in the CapexIM as a 20 year period from the date of commissioning of our investment proposal. A longer analysis period can be used if there is reasonable justification.

At this stage the commissioning date of our proposal – which is likely to be a portfolio of transmission and/or non-transmission components – is expected to be between when the need arises in winter 2021 and pre-winter 2023 following the retirement of the Rankine units, but some components could be commissioned later, for example if they could not be built in time.

We have therefore chosen an analysis period out to 2045.

Question 12	Is our proposed analysis period to 2045 reasonable for this project?

7.3.2 Value of expected unserved energy

The value of expected unserved energy (EUE) is the value placed on any unplanned electricity outage. We use this value to assess the benefit of reducing faults and other reasons that cause loss of supply.

The Code specifies that unserved energy is valued at $20,000/MWh. The $20,000/MWh was determined in December 2004. We propose to inflate it accordingly to a March 2016 value of $25,300/MWh using Statistics New Zealand's Consumer Price Index (CPI).

We can use a different value of EUE if we can substantiate the different value. Some industrial or other loads may have a cost of EUE which exceeds $25,300/MWh. For

example, a short power interruption to a milk powder plant may result in a requirement to clean and sterilise the plant.

Question 13	Do you think $25,300/MWh is appropriate for valuing expected unserved energy for this project? If you are a large industrial consumer, is $25,300/MWh appropriate to your own assessment of your cost of non-supply?

7.3.3 Discount rate

The CapexIM defines a standard real, pre-tax discount rate of 7% and high and low sentivities of 10% and 4% respectively.

We intend to use the discount rates included in the CapexIM for this analysis rather than propose non-standard values.

Question 14	Do you think our discount rate assumptions are reasonable? If not, what discount rates would you consider more appropriate for this analysis?

8 Feedback requested

As well as a vehicle for consulting on our draft long-list and assumptions, this document serves to invite interested persons to provide views or information on or relevant to possible non-transmission solutions to meet all or some of the need.

If you are aware of a non-transmission solution that may meet or assist in meeting the need, or any information that may be relevant to our assessment, we encourage you to make a submission. We also welcome your feedback on the long-list of components, demand growth and generation assumptions we have discussed and presented in this document.

If you have questions during the consultation period you may email them to WUNIVoltageManagement@transpower.co.nz and we will attempt to answer them within one week of receipt.

Queries and answers that Transpower considers may be of interest to others as well as any clarifications or corrections to this long-list consultation document will be posted on the website www.transpower.co.nz/waikato-and-upper-north-island-voltage-management-investigation. We will not disclose the originator of questions and may edit them accordingly.

Transpower will respond directly to queries that it considers are not material to others.

Following consultation, we will consider feedback received in submissions. Based on the information received, we will reconsider and finalise the long-list, demand growth and generation assumptions, and continue with the project as explained in section 6.

We seek written feedback by 5pm on Tuesday, 16 August 2016. Responses should be in electronic form, in either Microsoft Word or PDF format, and emailed to WUNIVoltageManagement@transpower.co.nz.

Our intent is to publish all submissions and further information on Transpower's website, at www.transpower.co.nz/waikato-and-upper-north-island-voltage-management-investigation.

If there is any aspect of your submission that is confidential, please:

- clearly mark the sections you consider confidential and indicate why
- indicate whether we can share the confidential information with the Commerce Commission

Transparency is important in this process and we may not be able to rely on confidential information to justify an investment proposal. Further, you should be aware that both Transpower and the Commerce Commission are subject to the provisions of the Official Information Act 1982.

A number of questions asked throughout this document are summarised in Appendix A. They are intended to aid your response. You are not obliged to answer all or any of these questions and are welcome to raise other issues which you believe might be relevant.

If you provide information on non-transmission solutions, please provide as much of the information listed in section 5.5 above as you are able.

We will acknowledge all submissions. Please note that late submissions may not be considered.

Thank you in advance for your assistance with this project.

Appendix A Consultation questions

Q1	Do you agree with our assessment of need and project scope? Are there any other issues or considerations relating to the need or scope that we should incorporate into this project?
Q2	Do you agree with our draft long-list of components? If not, what components should we include or remove?
Q3	This document serves as an invitation to provide information on non-transmission solutions. Any submission on this aspect should provide as much detail on the non-transmission solution as possible. Do you have any suggestions or proposals for non-transmission solutions to meet the need? If so, please provide the information requested (in section 5.5) so that we can apply a high-level assessment against our short-listing criteria.
Q4	Do you have any suggestions for enhancing Transpower's grid support contract (GSC) product design? If so, please provide your reasons, based on the rationale provided in our GSC design features document at www.transpower.co.nz/grid-support-contracts
Q5	Do you agree with our criteria for short-listing? If not, what criteria should we modify, include or remove, and why?
Q6	Do you think that the demand growth assumptions are appropriate for this project? If not, how could we improve them?
Q7	Do you think that, if the proposed removal of the DGPP and the RCPD charge from the TPM occur, net peak demand in the Upper North Island will be affected? If so, by how much?
Q8	Do you have any more detailed motor load information for the Upper North Island and Waikato that would allow us to improve our modelling?
Q9	Are you aware of any other existing generation in the UNI that we should include in our analysis?
Q10	Are you aware of any other dynamic reactive support sources that we should assume?

Q11	Do you think that the generation scenarios are appropriate for this project? If not, how could we improve them, especially with regard to our assumptions on generation that will be built at or north of Huntly?
Q12	Is our proposed analysis period to 2045 reasonable for this project?
Q13	Do you think $25,300/MWh is appropriate for valuing expected unserved energy for this project? If you are a large industrial consumer, is $25,300/MWh appropriate to your own assessment of your cost of non-supply?
Q14	Do you think our discount rate assumptions are reasonable? If not, what discount rates would you consider more appropriate for this analysis?

Appendix B Short-listing criteria

We propose to evaluate the long-list of components using a set of high-level screening criteria. The screening criteria will be used to eliminate those components that are not appropriate for consideration in the short-list of components and to which we apply the Investment Test. Broadly, we intend to use five criteria for screening:

1. Fit for purpose
2. Technical feasibility
3. Good electricity industry practice (GEIP)
4. System security (additional benefit resulting from an economic investment)
5. Indicative cost

Fit for purpose

The design will assist meeting future energy demand growth.

The extent to which the component resolves the relevant issue.

Practicability of implementing the component. It must be possible to implement the solution by the required dates (probability of proceeding).

- How long will it take to implement this component? Consideration includes:
  - Property acquisition time
  - Likelihood of gaining required environmental approvals
  - Equipment lead time
  - Time taken to build
- Implementation risks, including potential delays due to property and environmental issues
- Are there technical issues with access or available space for the works?
- Implementation risks e.g. are outage constraints on the existing system going to impact on this component?
- The availability of proponent for or potential counterparty to a transmission alternative

Technical feasibility

Complexity of component.

Reliability, availability and maintainability of the component

- Is this proven technology (i.e. used commercially, internationally and/or with available data on performance, and expected life cycle)?
- Does Transpower have experience with the technology?
- Is there a low level of risk associated with implementing this technology (such as ongoing maintenance requirements and availability of after sales support and spare parts)?

Future flexibility

- To what extent does the component open up or foreclose future development options?
- Future flexibility – fit with long term strategy for the grid, particularly as discussed in *Transmission Tomorrow*[26]
- Could the investment be stranded under certain conditions?

Good electricity industry practice (GEIP)[27]

Ensure safety

Consistent with good international practice

Minimise or mitigate environmental impacts

Accounts for relative size, duty, age and technological status

Manage technology risks

System security

Improved system security

System operator benefits (controllability)

- Does the component provide operational flexibility?

Indicative cost

Whether a component will clearly be more expensive than another component with similar or greater benefits

- The cost estimates, if used, are high level.

[26] See www.transpower.co.nz/transmission-tomorrow.
[27] Refer to Part 1 of the Code.

Appendix C Regional prudent peak demand and forecast power factor

Table C-1 shows regional prudent peak forecast for each region of interest (see section 2.4 for a definition).

Table C-1: 10-year region's forecast prudent peak demand

Region	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Northland	259	262	266	270	273	277	280	283	285	288
Auckland	2001	2056	2100	2136	2169	2200	2231	2255	2276	2301
Waikato	526	539	550	562	573	584	596	604	614	623
Upper North Island	2260	2318	2366	2406	2442	2477	2511	2537	2562	2589

Table C-2 shows demand and power factor at each grid exit point at the time of the regional prudent peak. Power factors indicate the proportion of active power (MW) to total power (MVA) at each grid exit point.

Table C-2: 10-year forecast peak demand and power factor at each grid exit point at time of regional prudent peak demand

Grid exit point	Power factor	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Northland											
Bream Bay	0.98	49	50	50	50	51	51	51	52	52	52
Kaikohe	-0.96	72	72	73	74	75	75	76	76	77	77
Maungatapere	0.98	94	96	98	99	101	103	105	106	108	109
Maungaturoto	1.00	15	16	16	16	16	17	17	17	17	18
Wellsford	1.00	29	29	30	30	31	31	32	32	32	33
Auckland											
Albany 33 kV	0.99	128	129	131	133	135	136	137	138	139	140
Albany 110 kV – Wairau Road	0.96	136	137	137	138	138	138	138	138	137	137
Bombay 33 kV	0.99	10	10	10	11	11	0	0	0	0	0
Bombay 110 kV	0.99	67	73	78	84	90	107	113	118	124	129
Glenbrook 33 kV	0.98	27	27	28	29	30	30	31	32	32	33
Glenbrook - NZ Steel	1.00	118	118	118	118	118	118	118	118	118	118
Henderson	1.00	126	133	141	149	157	165	174	182	189	197
Hepburn Road	1.00	139	140	141	142	143	144	144	145	145	145
Hobson Street	1.00	93	100	106	109	111	114	116	118	120	121
Mangere 33kV	0.98	109	112	115	118	121	123	126	128	130	132
Mangere 110 kV	0.90	19	19	19	19	19	19	19	19	19	19

Grid exit point	Power factor	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Meremere	0.99	1	1	1	1	1	1	1	1	1	1
Mt Roskill 22 kV	0.98	113	113	113	114	114	114	114	114	114	113
Mt Roskill 110 kV	1.00	39	39	39	40	40	40	40	40	39	39
Otahuhu	1.00	64	64	65	65	65	66	66	66	66	66
Pakuranga	0.99	138	138	139	140	141	141	141	141	141	141
Penrose 22 kV	0.98	36	41	41	41	42	42	42	42	42	42
Penrose 33 kV	0.98	273	286	289	293	296	299	302	304	305	307
Penrose 110 kV – Liverpool Street	1.00	93	100	106	109	111	114	116	118	120	121
Silverdale	1.00	83	84	86	87	89	90	91	92	93	94
Takanini	1.00	106	109	110	110	110	111	111	110	110	110
Wiri	1.00	82	84	85	87	88	90	91	92	93	94
Waikato											
Cambridge	0.98	35	36	37	38	38	39	40	41	42	43
Hamilton 11 kV	0.99	33	34	34	35	36	36	37	37	38	38
Hamilton 33 kV	0.99	122	125	128	130	132	135	137	139	141	143
Hamilton NZR	1.00	1	1	1	1	1	1	1	1	1	1
Hangatiki	0.92	25	26	27	27	28	29	29	30	30	31
Hinuera	0.97	38	39	40	25	26	26	27	27	28	28
Huntly	1.00	23	23	24	24	24	25	25	25	25	26
Kopu	1.00	43	44	45	46	47	48	49	50	51	52
Piako	0.97	28	29	30	31	31	32	33	34	35	36
Putaruru	1.00	0	0	0	17	18	18	18	19	19	19
Te Awamutu	0.98	32	32	33	33	34	34	35	35	35	36
Te Kowhai	0.99	86	87	89	90	91	93	94	95	96	97
Waihou	0.99	29	30	31	31	32	33	34	34	35	36
Waikino	1.00	31	32	33	34	35	36	36	37	38	38

Appendix D Regional expected peak demand and forecast power factor

Table D-1 shows the expected peak demand forecast for each region of interest (see section 2.4 for a definition).

Table D-1: 10-year region's forecast expected peak demand

Region	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Northland	252	253	255	258	260	262	265	267	270	272
Auckland	1908	1935	1963	1985	2006	2026	2046	2068	2088	2111
Waikato	510	519	527	536	544	553	561	570	579	587
Upper North Island	2159	2188	2218	2243	2265	2288	2311	2335	2358	2383

Table D-2 shows demand and power factor at each grid exit point at the time of the regional expected peak. Power factors indicate the proportion of active power (MW) to total power (MVA) at each grid exit point.

Table D-2: 10-year forecast peak demand and power factor at each grid exit point at the time of regional expected peak demand

Grid exit point	Power factor	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Northland											
Bream Bay	0.98	49	49	49	50	50	50	50	51	51	51
Kaikohe	-0.96	70	70	70	71	71	71	72	72	73	73
Maungatapere	0.98	89	89	90	92	93	94	95	97	98	99
Maungaturoto	1.00	15	16	16	16	16	16	17	17	17	17
Wellsford	1.00	29	29	29	30	30	30	31	31	32	32
Auckland											
Albany 33 kV	0.99	124	123	124	125	126	126	127	128	129	130
Albany 110 kV – Wairau Road	0.96	130	129	128	128	127	127	126	126	126	125
Bombay 33 kV	0.99	9	9	9	9	9	0	0	0	0	0
Bombay 110 kV	0.99	62	67	72	77	82	98	103	108	114	119
Glenbrook 33 kV	0.98	26	26	27	28	28	29	29	30	30	31
Glenbrook - NZ Steel	1.00	116	116	116	116	116	116	116	116	116	116
Henderson	1.00	118	122	129	135	142	149	156	163	170	177
Hepburn Road	1.00	133	131	131	132	132	132	132	132	132	132
Hobson Street	1.00	88	92	98	100	101	103	105	106	108	110
Mangere 33kV	0.98	105	106	108	110	112	114	116	118	119	121
Mangere 110 kV	0.90	18	18	18	18	18	18	18	18	18	18

Grid exit point	Power factor	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Meremere	0.99	1	1	1	1	1	1	1	1	1	1
Mt Roskill 22 kV	0.98	103	101	101	101	101	100	100	99	99	99
Mt Roskill 110 kV	1.00	36	35	35	35	35	35	35	35	34	34
Otahuhu	1.00	61	61	61	61	61	61	61	61	61	61
Pakuranga	0.99	130	129	129	129	128	128	128	128	128	128
Penrose 22 kV	0.98	34	38	38	38	38	38	38	38	39	39
Penrose 33 kV	0.98	266	274	275	277	278	280	281	283	284	286
Penrose 110 kV – Liverpool Street	1.00	88	92	98	100	101	103	105	106	108	110
Silverdale	1.00	80	80	81	82	83	84	85	86	87	87
Takanini	1.00	102	104	103	103	103	102	102	102	101	101
Wiri	1.00	80	80	81	82	83	84	85	86	86	88
Waikato											
Cambridge	0.98	34	35	35	36	37	37	38	39	40	40
Hamilton 11 kV	0.99	31	32	32	33	33	34	34	35	35	36
Hamilton 33 kV	0.99	121	123	125	126	128	130	132	134	136	138
Hamilton NZR	1.00	1	1	1	1	1	1	1	1	1	1
Hangatiki	0.92	25	26	26	27	27	28	28	29	29	30
Hinuera	0.97	37	38	39	25	25	25	26	26	26	27
Huntly	1.00	22	23	23	23	23	23	24	24	24	24
Kopu	1.00	41	42	43	44	45	46	47	47	48	49
Piako	0.97	27	28	29	29	30	31	32	32	33	34
Putaruru	1.00	0	0	0	17	17	17	17	18	18	18
Te Awamutu	0.98	30	31	31	31	31	32	32	32	33	33
Te Kowhai	0.99	81	82	83	83	84	85	86	87	88	89
Waihou	0.99	28	28	29	29	30	30	31	32	32	33
Waikino	1.00	31	31	32	32	33	34	34	35	36	36

Appendix E Contributions to WUNI prudent peak demand and forecast power factor

Table E-1 shows estimated load in each region of interest at time of the Waikato and Upper North Island prudent peak forecast.

Table E-1: 10-year region's forecast demand at the time of WUNI prudent peak

Region	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Northland	253	256	260	265	270	274	278	281	283	286
Auckland	2001	2056	2100	2136	2169	2200	2231	2255	2276	2301
Waikato	505	518	526	540	551	558	570	575	581	588
Upper North Island	2254	2312	2360	2401	2439	2474	2509	2536	2559	2587

Table E-2 shows demand and power factor at each grid exit point at the time of the prudent forecast WUNI peak. Power factors indicate the proportion of active power (MW) to total power (MVA) at each grid exit point.

Table E-2: 10-year forecast demand and power factor at each grid exit point at time of prudent WUNI peak

Grid exit point	Power factor	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Northland											
Bream Bay	0.98	42	43	43	43	44	44	44	45	45	45
Kaikohe	-0.96	72	72	73	75	76	76	77	78	78	79
Maungatapere	0.98	95	96	98	100	103	105	107	108	110	111
Maungaturoto	1.00	15	16	16	16	17	17	17	17	18	18
Wellsford	1.00	29	29	30	30	31	32	32	33	33	33
Auckland											
Albany 33 kV	0.99	128	129	131	133	135	136	137	138	139	140
Albany 110 kV – Wairau Road	0.96	136	137	137	138	138	138	138	138	137	137
Bombay 33 kV	0.99	10	10	10	11	11	0	0	0	0	0
Bombay 110 kV	0.99	67	73	78	84	90	107	113	118	124	129
Glenbrook 33 kV	0.98	27	27	28	29	30	30	31	32	32	33
Glenbrook - NZ Steel	1.00	118	118	118	118	118	118	118	118	118	118
Henderson	1.00	126	133	141	149	157	165	174	182	189	197
Hepburn Road	1.00	139	140	141	142	143	144	144	145	145	145
Hobson Street	1.00	93	100	106	109	111	113	116	118	119	121
Mangere 33kV	0.98	109	112	115	118	121	123	126	128	130	132
Mangere 110 kV	0.90	19	19	19	19	19	19	19	19	19	19

Grid exit point	Power factor	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Meremere	0.99	1	1	1	1	1	1	1	1	1	1
Mt Roskill 22 kV	0.98	113	113	113	114	114	114	114	114	113	113
Mt Roskill 110 kV	1.00	39	39	39	39	40	40	40	40	39	39
Otahuhu	1.00	64	64	65	65	65	66	66	66	66	66
Pakuranga	0.99	138	138	139	140	141	141	141	141	141	141
Penrose 22 kV	0.98	36	41	41	41	42	42	42	42	42	42
Penrose 33 kV	0.98	273	286	289	293	296	299	302	304	305	307
Penrose 110 kV – Liverpool Street	1.00	93	100	106	109	111	113	116	118	119	121
Silverdale	1.00	83	84	86	87	89	90	91	92	93	94
Takanini	1.00	106	109	110	110	110	110	111	110	110	110
Wiri	1.00	82	84	85	87	88	90	91	92	93	94
Waikato											
Cambridge	0.98	35	36	36	37	38	39	40	40	40	41
Hamilton 11 kV	0.99	33	34	34	35	35	36	36	36	37	37
Hamilton 33 kV	0.99	122	125	126	129	131	133	135	136	136	138
Hamilton NZR	1.00	1	1	1	1	1	1	1	1	1	1
Hangatiki	0.92	25	26	26	27	28	28	29	29	29	30
Hinuera	0.97	38	39	40	25	26	26	27	27	27	27
Huntly	1.00	23	23	23	24	24	24	25	25	25	25
Kopu	1.00	43	44	45	46	47	48	49	49	50	50
Piako	0.97	28	29	29	30	31	32	33	33	34	34
Putaruru	1.00	0	0	0	17	17	18	18	18	18	18
Te Awamutu	0.98	32	32	32	33	34	34	34	34	34	34
Te Kowhai	0.99	65	67	69	70	71	74	75	77	79	81
Waihou	0.99	29	30	30	31	32	32	33	34	34	34
Waikino	1.00	31	32	33	34	34	35	36	36	36	37

Appendix F Contributions to WUNI expected peak demand and forecast power factor

Table F-1 shows estimated load in each region of interest at time of expected Waikato and Upper North Island expected peak forecast.

Table F-1: 10-year region's forecast demand at the time of expected WUNI peak

Region	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Northland	239	240	243	245	247	250	252	254	257	260
Auckland	1908	1935	1963	1985	2006	2026	2046	2068	2088	2111
Waikato	481	483	484	491	497	501	507	512	517	524
Upper North Island	2151	2177	2206	2231	2254	2276	2299	2323	2345	2371

Table F-2 shows demand and power factor at each grid exit point at the time of the expected forecast WUNI peak. Power factors indicate the proportion of active power (MW) to total power (MVA) at each grid exit point.

Table F-2: 10-year forecast demand and power factor at each grid exit point at time of expected WUNI peak

Grid exit point	Power factor	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Northland											
Bream Bay	0.98	39	39	39	40	40	40	40	41	41	41
Kaikohe	-0.96	66	66	66	67	67	67	68	68	69	69
Maungatapere	0.98	90	91	92	94	95	96	97	98	100	101
Maungaturoto	1.00	15	15	16	16	16	16	16	17	17	17
Wellsford	1.00	28	29	29	29	30	30	30	31	31	32
Auckland											
Albany 33 kV	0.99	124	123	124	125	126	126	127	128	129	130
Albany 110 kV – Wairau Road	0.96	130	129	128	128	127	127	126	126	126	125
Bombay 33 kV	0.99	9	9	9	9	9	0	0	0	0	0
Bombay 110 kV	0.99	62	66	72	77	82	98	103	108	113	119
Glenbrook 33 kV	0.98	26	26	27	27	28	29	29	30	30	31
Glenbrook - NZ Steel	1.00	116	116	116	116	116	116	116	116	116	116
Henderson	1.00	118	122	129	135	142	149	156	163	170	177
Hepburn Road	1.00	133	131	131	132	132	132	132	132	132	132
Hobson Street	1.00	88	92	98	100	101	103	105	106	108	110
Mangere 33kV	0.98	105	106	108	110	112	114	116	118	119	121
Mangere 110 kV	0.90	18	18	18	18	18	18	18	18	18	18

Grid exit point	Power factor	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Meremere	0.99	1	1	1	1	1	1	1	1	1	1
Mt Roskill 22 kV	0.98	103	101	101	101	101	100	100	99	99	99
Mt Roskill 110 kV	1.00	36	35	35	35	35	35	35	35	34	34
Otahuhu	1.00	61	61	61	61	61	61	61	61	61	61
Pakuranga	0.99	130	129	129	129	128	128	128	128	128	128
Penrose 22 kV	0.98	34	38	38	38	38	38	38	38	38	39
Penrose 33 kV	0.98	266	274	275	277	278	280	281	283	284	286
Penrose 110 kV – Liverpool Street	1.00	88	92	98	100	101	103	105	106	108	110
Silverdale	1.00	80	80	81	82	83	84	85	86	86	87
Takanini	1.00	102	104	103	103	103	102	102	102	101	101
Wiri	1.00	80	80	81	82	83	84	84	86	86	88
Waikato											
Cambridge	0.98	33	33	33	34	34	35	35	36	36	37
Hamilton 11 kV	0.99	30	31	30	31	31	31	32	32	32	32
Hamilton 33 kV	0.99	118	118	118	119	121	121	122	123	124	126
Hamilton NZR	1.00	1	1	1	1	1	1	1	1	1	1
Hangatiki	0.92	25	25	25	25	26	26	26	27	27	27
Hinuera	0.97	37	37	37	23	23	23	24	24	24	24
Huntly	1.00	22	22	22	22	22	22	22	22	22	22
Kopu	1.00	40	41	41	41	42	42	43	44	44	45
Piako	0.97	27	27	27	28	28	29	29	30	30	31
Putaruru	1.00	0	0	0	16	16	16	16	16	16	16
Te Awamutu	0.98	30	29	29	29	30	29	30	30	30	30
Te Kowhai	0.99	61	62	63	64	65	66	66	67	68	69
Waihou	0.99	27	27	27	28	28	28	29	29	29	30
Waikino	1.00	30	30	30	31	31	31	32	32	33	33

Appendix G Forecast call profiles for demand response

For potential proponents of demand response non-transmission solutions, we have forecast information on the possible call profiles for 2021 and 2022. To produce this information we have considered:

1. Expected and prudent demand forecasts for the Upper North Island (see section 2.4 for a definition)
2. Historical demand profiles from 2006 to 2015, and
3. N-G-1 Upper North Island load limits (see section 2.3 for a definition)

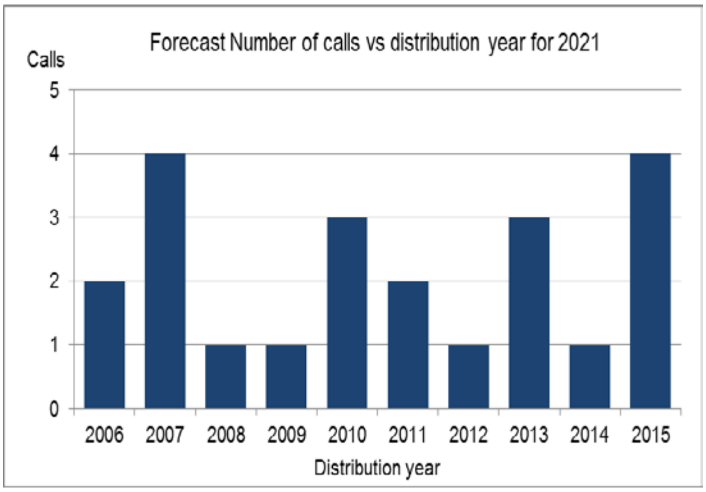
Historical demand profiles

The demand profile varies from one year to another year, most particularly according to the weather in that year. To demonstrate the effect of this variability on the call profile for the Upper North Island, we have plotted the expected number of calls for 2021 and 2022 using the actual annual demand profiles from 2006 to 2015.

There are no expected calls using expected (P50) peak demand forecasts pre-2023, the retirement of the remaining Huntly Rankine units.

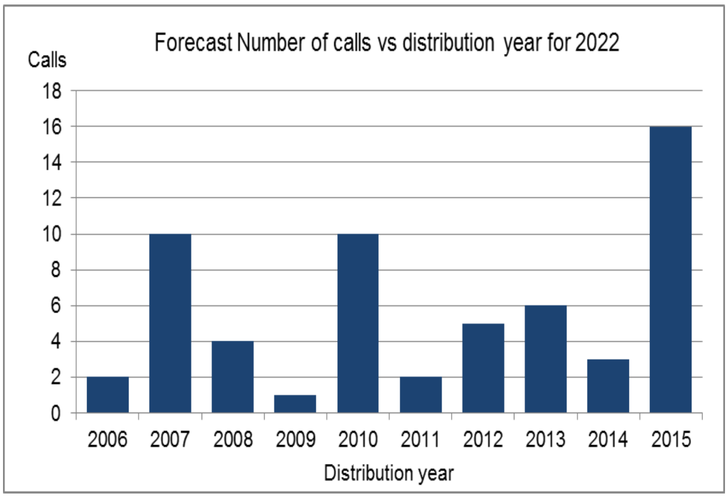
The forecast ranges of calls using prudent peak demand forecasts are shown in Figure G-1 and Figure G-2.

Figure G-1: Forecast calls for 2021 – actual demand profiles and prudent peak demand growth



Mean 2

Figure G-2: Forecast calls for 2022 – actual demand profiles and prudent peak demand growth



Mean 6

As can be seen, the expected number of calls varies depending on the historical profile used. For the purposes of deriving more detailed call information below, we have used the 2009 and 2015 profiles, being reasonably representative of the likely bounds for 2021 to 2025.

Forecast load profile

We have also assessed the MW required each year, the likely number of demand response calls and average length of calls to be made.

These assessments are based on 2009 and 2015 historical profiles and demand forecasts, and are for information only.

Table G-1: Forecast MW, number of calls, average length of calls – 2009 load profile

Year	Total energy not served (MWh)	Mean demand response block (MW)	Maximum demand response block (MW)	Forecast number of 1/2 periods	Forecast Number of calls	Ave length of call (hrs)
Prudent forecast						
2021	12	24	24	1	1	0.5
2022	30	59	59	1	1	0.5
2023	30,015	116	436	517	115	2.2
2024	35,469	123	459	578	127	2.3
2025	42,976	131	487	657	140	2.3
Expected forecast						
2021	-	-	-	-	-	-
2022	-	-	-	-	-	-
2023	2,943	53	223	111	37	1.5
2024	4,168	63	245	133	41	1.6
2025	6,056	70	271	173	49	1.8

Table G-2: Forecast MW, number of calls, average length of calls – 2015 load profile

Year	Total energy not served (MWh)	Mean demand response block (MW)	Maximum demand response block (MW)	Forecast number of 1/2 periods	Forecast Number of calls	Ave length of call (hrs)
Prudent forecast						
2021	28	14	24	4	4	0.5
2022	247	22	59	22	16	0.7
2023	88,043	150	436	1,174	200	2.9
2024	100,486	160	459	1,260	210	3.0
2025	116,857	166	487	1,407	222	3.2
Expected forecast						
2021	-	-	-	-	-	-
2022	-	-	-	-	-	-
2023	15,417	80	223	385	98	2.0
2024	19,699	88	245	447	110	2.0
2025	25,721	95	271	541	127	2.1

See also the discussion on demand forecasting issues in section 2.9 of the Grid Support Contract design features document[28].

[28] See www.transpower.co.nz/grid-support-contracts.

Appendix H Generation scenarios

Table H-1 includes generation build schedules for each generation build schedule. As discussed in section 7.2.3, we have based these scenarios on MBIE's draft EDGS and the New Zealand Smart Grid Forum' Disruptive Technology scenario but modified them to reflect new information and to ensure there is enough regional diversity to test our investment options.

We have defined five broad regions for replacement generation following the retirement of the remaining Rankine units:

- **Bay of Plenty:** The remaining Rankine units retire in 2022 and generation expansion is focussed in the Bay of Plenty
- **Taranaki:** The remaining Rankine units retire in 2022 and generation expansion is focussed in Taranaki
- **Lower North Island and South Island:** The remaining Rankine units retire in 2022 and generation expansion is focussed to the south of Bunnythorpe
- **Central North Island:** The remaining Rankine units retire in 2022 and generation expansion is focussed in the region between Bunnythorpe and Wairakei.
- **Waikato and Upper North Island:** The remaining Rankine units are replaced with similar capacity at Huntly or further north (or stay in service).

We will update the build schedules presented below based on feedback from this consultation, developments in the industry and the final EDGS when it is released.

Table H-1: Generation Scenarios

Scenario	Year	Plant	Technology	Build/ retirement	Resulting MW	Region
Scenario 1 – Huntly and North	2017	ToddPeaker-JunctionRd	Gas Peaker	build	100	Taranaki
	2018	Kawerau TeAhiOMaui KA22	Geothermal	build	27	Bay of Plenty
		ToddPeaker npl	Gas Peaker	build	100	Taranaki
	2019	New Huntly Gas Peaker	Gas Peaker	build	200	Waikato
		Whakamaru Upgrade	Hydro	build	20	Waikato
		Wairau	Hydro	build	70	Nelson/ Marlborough
	2020	Ngawha expansion stage one	Geothermal	build	25	North of Auckland
		Tauhara stage 2	Geothermal	build	250	Central North Island
	2022	CCGT Cogen generic 2	Gas Cogeneration	build	40	Taranaki
	2023	Huntly coal unit 1	Coal	retire	0	Waikato
		Huntly Coal unit 2	Coal	retire	0	Waikato

Scenario	Year	Plant	Technology	Build/ retirement	Resulting MW	Region
		Rotokawa generic1	Geothermal	build	130	Central North Island
		New Huntly CCGT	Combined-cycle Gas Turbine	build	475	Waikato
	2025	Tauhara generic1	Geothermal	build	80	Central North Island
	2026	Hauauru ma raki stage1	Wind	build	252	Waikato
	2028	Turitea	Wind	build	52	Central North Island
	2029	Turitea	Wind	build	144	Central North Island
		Huntly unit 6 (P40)	Open-cycle Gas Turbine	retire	0	Waikato
	2030	Ngatamariki generic1	Geothermal	build	100	Central North Island
	2031	Hawkes Bay windfarm Maungaharuru	Wind	build	10	Hawke's Bay
		Turitea	Wind	build	183	Central North Island
	2032	Hawkes Bay windfarm Maungaharuru	Wind	build	129	Hawke's Bay
	2033	CastleHill stage2	Wind	build	2	Wellington
		Hawkes Bay windfarm Maungaharuru	Wind	build	225	Hawke's Bay
	2034	CastleHill stage2	Wind	build	57	Wellington
		Arnold	Hydro	build	46	West Coast
	2035	CastleHill stage2	Wind	build	192	Wellington
	2036	CastleHill stage2	Wind	build	270	Wellington
		CastleHill stage3	Wind	build	73	Wellington
		Lake Coleridge 2	Hydro	build	70	Canterbury
	2037	CastleHill stage3	Wind	build	197	Wellington
	2038	Tikitere LakeRotoiti	Geothermal	build	45	Bay of Plenty
		CastleHill stage3	Wind	build	270	Wellington
	2039	Generic LargeWind1 Manawatu stage1	Wind	build	250	Central North Island
		Generic LargeWind1 Manawatu stage2	Wind	build	250	Central North Island
	2040	Waitahora	Wind	build	23	Wellington
	2041	TikitereTaheke generic2	Geothermal	build	80	Bay of Plenty
		Generic MediumWind4 HawkesBay	Wind	build	24	Hawke's Bay
	2042	Generic MediumWind4 HawkesBay	Wind	build	170	Hawke's Bay
		Mahinerangi	Wind	build	1	Otago/Southland

Scenario	Year	Plant	Technology	Build/ retirement	Resulting MW	Region
		stage 2				
	2043	Ngawha generic2	Geothermal	build	25	North of Auckland
		Generic MediumWind4 HawkesBay	Wind	build	174	Hawke's Bay
	2044	North Bank Tunnel	Hydro	build	260	Otago/Southland
	2045	Taharoa	Wind	build	54	Waikato
		Generic MediumWind4 HawkesBay	Wind	build	200	Hawke's Bay
Scenario 2 – Bay of Plenty	2017	ToddPeaker-JunctionRd	Gas Peaker	build	100	Taranaki
	2018	Kawerau TeAhiOMaui KA22	Geothermal	build	27	Bay of Plenty
		New Taranaki Gas Peaker	Gas Peaker	build	100	Taranaki
	2019	Whakamaru Upgrade	Hydro	build	20	Waikato
		Wairau	Hydro	build	70	Nelson/ Marlborough
	2020	Ngawha expansion stage one	Geothermal	build	25	North of Auckland
		Tauhara stage 2	Geothermal	build	250	Central North Island
	2021	Tauhara generic1	Geothermal	build	80	Central North Island
	2022	Rotokawa generic1	Geothermal	build	130	Central North Island
	2023	Huntly coal unit 1	Coal	retire	0	Waikato
		Huntly Coal unit 2	Coal	retire	0	Waikato
		Rotoma LakeRotoma	Geothermal	build	35	Bay of Plenty
		Tikitere LakeRotoiti	Geothermal	build	45	Bay of Plenty
		Hawea Control Gate Retrofit	Hydro	build	17	Otago/Southland
		Lake Pukaki	Hydro	build	35	Canterbury
		Stockton Mine	Hydro	build	35	West Coast
	2024	Turitea	Wind	build	183	Central North Island
	2025	Ngatamariki generic1	Geothermal	build	100	Central North Island
		Hawkes Bay windfarm Maungaharuru	Wind	build	201	Hawke's Bay
	2026	Hawkes Bay windfarm Maungaharuru	Wind	build	225	Hawke's Bay
	2028	TikitereTaheke	Geothermal	build	160	Bay of Plenty

Scenario	Year	Plant	Technology	Build/ retirement	Resulting MW	Region
		generic1				
	2030	TikitereTaheke generic2	Geothermal	build	80	Bay of Plenty
	2031	Rotokawa generic2	Geothermal	build	130	Central North Island
	2032	CastleHill stage2	Wind	build	23	Wellington
	2033	CastleHill stage2	Wind	build	152	Wellington
	2034	CastleHill stage2	Wind	build	266	Wellington
	2035	CastleHill stage2	Wind	build	270	Wellington
		CastleHill stage3	Wind	build	199	Wellington
	2036	CastleHill stage3	Wind	build	270	Wellington
		Generic MediumWind4 HawkesBay	Wind	build	6	Hawke's Bay
		Arnold	Hydro	build	46	West Coast
	2037	Generic MediumWind4 HawkesBay	Wind	build	130	Hawke's Bay
	2038	Lake Coleridge 2	Hydro	build	70	Canterbury
	2039	Generic LargeWind1 Manawatu stage1	Wind	build	250	Central North Island
		Generic LargeWind1 Manawatu stage2	Wind	build	38	Central North Island
	2040	Generic LargeWind1 Manawatu stage2	Wind	build	171	Central North Island
	2041	Generic LargeWind1 Manawatu stage2	Wind	build	250	Central North Island
		Generic MediumWind4 HawkesBay	Wind	build	165	Hawke's Bay
		Mahinerangi stage 2	Wind	build	4	Otago/Southland
	2042	Generic MediumWind4 HawkesBay	Wind	build	183	Hawke's Bay
		Mahinerangi stage 2	Wind	build	27	Otago/Southland
		Stockton Plateau	Hydro	build	25	West Coast
	2043	Generic MediumWind4 HawkesBay	Wind	build	186	Hawke's Bay
	2044	Generic MediumWind4 HawkesBay	Wind	build	200	Hawke's Bay
		Mahinerangi stage 2	Wind	build	147	Otago/Southland
	2045	Mahinerangi stage 2	Wind	build	164	Otago/Southland
		Puketoi	Wind	build	36	Wellington
		Taharoa	Wind	build	54	Waikato

Scenario	Year	Plant	Technology	Build/ retirement	Resulting MW	Region
		Waitahora	Wind	build	156	Wellington
Scenario 3 - Taranaki	2017	ToddPeaker-JunctionRd	Gas Peaker	build	100	Taranaki
	2018	Kawerau TeAhiOMaui KA22	Geothermal	build	27	Bay of Plenty
		New Taranaki Gas Peaker	Gas Peaker	build	100	Taranaki
	2019	OCGT diesel peaker generic 2	#N/A	build	200	Hawke's Bay
		Whakamaru Upgrade	Hydro	build	20	Waikato
	2021	Project CentralWind	Wind	build	26	Central North Island
	2023	Huntly coal unit 1	Coal	retire	0	Waikato
		Huntly Coal unit 2			0	
		New Taranaki CCGT	Combined-cycle Gas Turbine	build	475	Taranaki
		New Taranaki Gas Peaker	Gas Peaker	build	200	Taranaki
		Lake Pukaki	Hydro	build	35	Canterbury
	2024	Rotokawa generic1	Geothermal	build	130	Central North Island
	2025	Tauhara stage 2	Geothermal	build	250	Central North Island
	2030	Ngatamariki generic1	Geothermal	build	100	Central North Island
	2032	Hawea Control Gate Retrofit	Hydro	build	17	Otago/Southland
	2034	Tauhara generic1	Geothermal	build	80	Central North Island
	2035	New Huntly CCGT	Combined-cycle Gas Turbine	build	475	Waikato
	2037	Wairau	Hydro	build	70	Nelson/ Marlborough
	2039	Turitea	Wind	build	175	Central North Island
		Stockton Mine	Hydro	build	35	West Coast
	2040	Hawkes Bay windfarm Maungaharuru	Wind	build	123	Hawke's Bay
		Turitea	Wind	build	183	Central North Island
	2041	TikitereTaheke generic2	Geothermal	build	80	Bay of Plenty
	2042	Hawkes Bay windfarm Maungaharuru	Wind	build	225	Hawke's Bay
	2044	Arnold	Hydro	build	46	West Coast
		Lake Coleridge 2	Hydro	build	70	Canterbury
	2045	Tikitere LakeRotoiti	Geothermal	build	45	Bay of Plenty
		Generic LargeWind1	Wind	build	153	Central North

Scenario	Year	Plant	Technology	Build/ retirement	Resulting MW	Region
		Manawatu stage1				Island
		Stockton Plateau	Hydro	build	25	West Coast
Scenario 4 – Lower NI and South	2017	ToddPeaker-JunctionRd	Gas Peaker	build	100	Taranaki
	2018	Kawerau TeAhiOMaui KA22	Geothermal	build	27	Bay of Plenty
		CCGT Cogen generic 2	Gas cogeneration	build	40	Taranaki
		New Taranaki Gas Peaker	Gas Peaker	build	100	Taranaki
		Whakamaru Upgrade	Hydro	build	20	Waikato
		Hawea Control Gate Retrofit	Hydro	build	17	Otago/Southland
		Lake Pukaki	Hydro	build	35	Canterbury
		Stockton Mine	Hydro	build	35	West Coast
	2020	Project CentralWind	Wind	build	61	Central North Island
		Waitahora	Wind	build	156	Wellington
	2021	Project CentralWind	Wind	build	120	Central North Island
		Arnold	Hydro	build	46	West Coast
	2022	Taharoa	Wind	build	54	Waikato
	2023	Huntly coal unit 1	Coal	retire	0	Waikato
		Huntly Coal unit 2	Coal	retire	0	Waikato
		Rotokawa generic1	Geothermal	build	130	Central North Island
		CastleHill stage1	Wind	build	60	Wellington
		CastleHill stage2	Wind	build	270	Wellington
		Kaiwera Downs	Wind	build	240	Otago/Southland
		Mahinerangi stage 2	Wind	build	33	Otago/Southland
		Wairau	Hydro	build	70	Nelson/ Marlborough
	2024	Turitea	Wind	build	183	Central North Island
	2025	Tauhara stage 2	Geothermal	build	250	Central North Island
		Hawkes Bay windfarm Maungaharuru	Wind	build	84	Hawke's Bay
	2026	Hawkes Bay windfarm Maungaharuru	Wind	build	225	Hawke's Bay
	2027	Mohikinui	Hydro	build	100	West Coast
	2028	Tikitere LakeRotoiti	Geothermal	build	45	Bay of Plenty
		CastleHill stage3	Wind	build	140	Wellington
	2029	CastleHill stage3	Wind	build	244	Wellington

Scenario	Year	Plant	Technology	Build/ retirement	Resulting MW	Region
		Huntly unit 6 (P40)	Open-cycle Gas Turbine	retire	0	Waikato
	2030	Ngatamariki generic1	Geothermal	build	100	Central North Island
		Project Hayes stage 1	Wind	build	126	Otago/Southland
		Project Hayes stage 2	Wind	build	160	Otago/Southland
	2031	Project Hayes stage 1	Wind	build	151	Otago/Southland
	2033	Lake Coleridge 2	Hydro	build	70	Canterbury
		Stockton Plateau	Hydro	build	25	West Coast
	2034	Mohaka	Hydro	build	44	Hawke's Bay
	2035	Waverley Wind	Wind	build	130	Taranaki
		Hurunui	Hydro	build	70	Canterbury
	2036	Hauauru ma raki stage1	Wind	build	252	Waikato
	2040	Project Hayes stage 3	Wind	build	135	Otago/Southland
		Project Hayes stage 4	Wind	build	35	Otago/Southland
	2041	Project Hayes stage 4	Wind	build	57	Otago/Southland
		North Bank Tunnel	Hydro	build	260	Otago/Southland
	2042	Project Hayes stage 4	Wind	build	93	Otago/Southland
	2043	Kawerau generic2	Geothermal	build	30	Bay of Plenty
		Mangakino generic1	Geothermal	build	40	Waikato
		Rotoma generic1	Geothermal	build	35	Bay of Plenty
		Project Hayes stage 4	Wind	build	129	Otago/Southland
	2044	Rotoma LakeRotoma	Geothermal	build	35	Bay of Plenty
		Project Hayes stage 3	Wind	build	160	Otago/Southland
	2045	Generic LargeWind1 Manawatu stage1	Wind	build	12	Central North Island
		Project Hayes stage 4	Wind	build	160	Otago/Southland
		Kaipara Tidal	Tidal	build	60	North of Auckland
Scenario 5 – Central NI and Hawkes Bay	2017	ToddPeaker-JunctionRd	Gas Peaker	build	100	Taranaki
	2018	Kawerau TeAhiOMaui KA22	Geothermal	build	27	Bay of Plenty
		Rotoma LakeRotoma	Geothermal	build	35	Bay of Plenty

Scenario	Year	Plant	Technology	Build/ retirement	Resulting MW	Region
		New Taranaki Gas Peaker	Gas Peaker	build	100	Taranaki
	2019	New Huntly Gas Peaker	Gas Peaker	build	200	Waikato
		Whakamaru Upgrade	Hydro	build	20	Waikato
		Hawea Control Gate Retrofit	Hydro	build	17	Otago/Southland
		Lake Pukaki	Hydro	build	35	Canterbury
	2020	Ngawha expansion stage one	Geothermal	build	25	North of Auckland
		Tauhara stage 2	Geothermal	build	250	Central North Island
	2021	Turitea	Wind	build	183	Central North Island
	2022	CCGT Cogen generic 1	Gas cogeneration	build	40	Waikato
	2023	Huntly coal unit 1	Coal	retire	0	Waikato
		Huntly Coal unit 2	Coal	retire	0	Waikato
		Rotokawa generic1	Geothermal	build	130	Central North Island
		Tauhara generic1	Geothermal	build	80	Central North Island
		Project CentralWind	Wind	build	120	Central North Island
		Hawkes Bay windfarm Maungaharuru	Wind	build	225	Hawke's Bay
	2024	Wairau	Hydro	build	70	Nelson/ Marlborough
	2026	Stockton Mine	Hydro	build	35	West Coast
	2027	CastleHill stage2	Wind	build	110	Wellington
	2028	CastleHill stage2	Wind	build	270	Wellington
	2030	Ngatamariki generic1	Geothermal	build	100	Central North Island
	2031	Tikitere LakeRotoiti	Geothermal	build	45	Bay of Plenty
	2032	Tauhara generic2	Geothermal	build	80	Central North Island
		New Taranaki CCGT	Combined-cycle Gas Turbine	build	475	Taranaki
	2034	Ngawha generic2	Geothermal	build	25	North of Auckland
		Arnold	Hydro	build	46	West Coast
		Lake Coleridge 2	Hydro	build	70	Canterbury
		Stockton Plateau	Hydro	build	25	West Coast
	2036	Rotoma generic1	Geothermal	build	35	Bay of Plenty
		CastleHill stage3	Wind	build	41	Wellington
		Mohaka	Hydro	build	44	Hawke's Bay
	2037	CastleHill stage3	Wind	build	184	Wellington
		Generic MediumWind4	Wind	build	31	Hawke's Bay

Scenario	Year	Plant	Technology	Build/ retirement	Resulting MW	Region
		HawkesBay				
	2038	CastleHill stage3	Wind	build	270	Wellington
		Generic MediumWind4 HawkesBay	Wind	build	147	Hawke's Bay
	2039	Generic LargeWind1 Manawatu stage1	Wind	build	250	Central North Island
		Generic LargeWind1 Manawatu stage2	Wind	build	250	Central North Island
		Generic MediumWind4 HawkesBay	Wind	build	184	Hawke's Bay
	2040	Generic MediumWind4 HawkesBay	Wind	build	200	Hawke's Bay
		Kaiwera Downs	Wind	build	36	Otago/Southland
	2041	Kawerau generic2	Geothermal	build	30	Bay of Plenty
		Kaiwera Downs	Wind	build	102	Otago/Southland
	2042	Mangakino generic1	Geothermal	build	40	Waikato
		Kaiwera Downs	Wind	build	163	Otago/Southland
	2043	Kaiwera Downs	Wind	build	211	Otago/Southland
	2044	New Huntly CCGT	Combined-cycle Gas Turbine	build	475	Waikato

Appendix I Grid support contract design features

For the rationale behind each design feature, please refer to Transpower's grid support contact design document, available at www.transpower.co.nz/grid-support-contracts.

#	GSC design feature
1	GSCs will be specific to transmission capacity problems for which transmission investment is under consideration, and hence offered only for specific regions and periods when these are occurring, or are forecast to occur
2	GSCs will be considered to facilitate the management of outages that are driving transmission investment timing, to achieve more optimal transmission investment, or are necessary to implementing an investment GSCs will not be considered as mechanisms to manage other and routine outage management issues for which transmission investment is not under consideration
3	Any GSCs entered into will be relied on operationally to ensure continuous delivery of electricity to end users: Transpower will operate the grid on the assumption that any GSCs entered into will deliver the contracted services
4	GSCs will be designed to complement existing market arrangements and to: • minimise distortions in electricity generation investment • avoid Transpower becoming relied on for energy as well as transmission capacity provision
5	GSCs will not be offered if they would compromise other security products, including ancillary services and extended reserves, or the markets for these products GSCs will require that there is no physical 'double dipping' between GSC operation and operation of the GSC resources in an ancillary service market
6	GSCs for DSP and market generation are likely to be viable for short-term measures only, perhaps for say 1 or 2, or maybe 3 years The increasing impact with time will be assessed on a case-by-case basis
7	Before entering into a GSC, Transpower will seek technical as well as commercial assurance that the service providers under the GSC will be available and operate as required
8	All forms of pre-contingent and post-contingent GSC options will be considered
9	Transpower will take the impact of expected forecasting errors into account in evaluating the reliability and cost of entering into GSCs (at the time of evaluating GSC proposals), and in calling GSCs
10	Transpower offers three types of GSCs: • risk management GSCs • transmission deferral GSCs ('deferral GSCs') • voltage support GSCs
11	Transpower will offer deferral GSCs to defer investment in interconnection assets only
12	GSCs will be contracts for grid support services **Transpower will not use GSCs to take ownership of any assets**
13	Transpower will only offer GSCs where it has approval to recover their costs through the TPM • as part of an approved MCP (or existing GUP) • as part of Transpower's opex

<table>
<tr><th>#</th><th>GSC design feature</th></tr>
<tr><td>14</td><td>Transpower will only offer GSCs where they can assist in meeting the grid reliability standards</td></tr>
<tr><td>15</td><td>Transpower will implement a competitive procurement approach for GSCs, including:
preparatory information provision
invitation for information (as part of the long-list consultation)
request for proposals (RFP)
tender evaluation and selection</td></tr>
<tr><td>16</td><td>Transpower will in its long-list consultation document define the need for transmission and/or non-transmission solutions, including providing as much information as possible on the possible range of:
capacity shortfalls versus time
size, shape and frequency of capacity shortfalls</td></tr>
<tr><td>17</td><td>Transpower will issue an RFP where the long-listing process has identified that there are expected to be appropriate, reliable and economic non-transmission solutions to meet the need
The RFP will:
specify the need (possibly refined from that in the long-listing process, consequent on information received and further analysis)
invite proponents to make a commercial proposal to provide grid support services through a GSC that would meet some or all of the need</td></tr>
<tr><td>18</td><td>Qualification criteria will specify the minimum requirements for a particular GSC</td></tr>
<tr><td>19</td><td>Evaluation criteria will be used to specify how GSC proposals will be evaluated against each other and against transmission solutions</td></tr>
<tr><td>20</td><td>Transpower will evaluate GSC proposals in two:
Firstly, individually evaluate each GSC proposal
Secondly, assess the GSC proposals as a group to develop a portfolio of GSCs that best meets the full range of reasonably foreseeable requirements</td></tr>
<tr><td>21</td><td>Transpower will in its long-listing and RFP processes specify the possible locations of resources for the supply of GSC services and, where relevant and practical, indicate the relative merits of resources at different locations</td></tr>
<tr><td>22</td><td>Transpower will endeavour to provide adequate notice of future need, but recognises that especially for risk management GSCs need can occur at relatively short notice</td></tr>
<tr><td>23</td><td>Transpower will have two approval approaches for GSCs in MCPs, both as part (or all) of a reliability investment proposal:
specific GSC approval, for approval of specific GSC contracts
generic GSC approval, for approval of a future GSC procurement process
Both approaches may be combined in one reliability investment proposal, and will be accompanied by an appropriate physical and financial scope of the approval</td></tr>
<tr><td>24</td><td>Transpower offers three forms of GSC:
demand-side participation (DSP) including non-market generation
voltage support
market generation</td></tr>
<tr><td>25</td><td>GSC proponents and providers do not need to be participants under the Code</td></tr>
</table>

#	GSC design feature
26	GSC contracts will include requirements for testing Transpower will reserve the right to make calls to test operational readiness
27	Transpower may accept an emergent technology that has not as yet demonstrated appropriate reliability as part of a solution mix so long as overall solution reliability can be achieved
	For GSCs for DSP including non-market generation only
28	GSCs for DSP will allow for blocks comprising one of: • a single load resource • a single non-market generation resource • an aggregation of multiple load and/or non-market generation resources
29	Transpower will require GSCs for DSP to deliver reliable: • load reduction, where the service is to reduce net load by an agreed amount, or a • load cap, where the service is to limit net load at a certain location to an agreed amount
30	GSCs for DSP will either be: • called by Transpower as required ahead of real time • operated automatically post-contingency (for operational contingencies) • called by Transpower post-contingency (for planning-only contingencies)
31	Transpower will, where reasonably practical and meaningful, provide historical load data and non-binding probabilistic estimates of how often and under what conditions (e.g. call durations, timings and sequencing) DSP might be called. These will be for information only and will not affect operational calls
32	Transpower may define in its RFP a minimum block size in order to keep the number of blocks manageable by the System Operator
33	Transpower expects aggregators to contract for resources of total capacity significantly greater than the contracted block capacity, to allow for the risk of resource non-availability or failure Transpower expects aggregators to manage blocks through adding or substituting resources if and when necessary to maintain block reliability and capability over time

34	A payment structure will be proposed as part of the RFP process, based on some or all of:
	• Preparation payments
	  o establishment payment to cover up-front costs of participation
	• Operation payments
	  o availability: payment for being available to call, per month, conditional on not failing to deliver against calls (including test calls)
	  o delivery: payment per MW delivered per hour up to the contracted amount
	Transpower will consider variants on this mechanism or other payment structures, but will require that the payment structures for GSCs for DSP include financial incentives for performance

35	Providers will be required to meet specified communications requirements to for example accept and acknowledge calls Aggregators will be required to have reliable call and acknowledgement processes between themselves and all of their resources
36	Transpower will enter into GSCs for DSP only with resources that offer DSP additional to what would be expected to occur otherwise

#	GSC design feature
37	GSCs for DSP within distribution networks will require each source, the aggregator or Transpower to notify its: • retailer • local distribution network
38	Providers will be required to verify the delivery for each called resource for each call as the basis for payment. Verification must: • for a load reduction service, demonstrate additionality to that which would otherwise have occurred in that call period • for a load cap service, demonstrate that load was no greater than the cap throughout the call period • demonstrate that load did not rebound beyond any contracted limits for the recovery period For aggregators: • verification for each called resource must cover the full call period and any call recovery period specified • while verification will be at the resource level, delivery relative to the contracted amount will be at block level across all called resources for the full call period and any call recovery period specified Transpower will require some standardisation of verification methods and reporting formats
39	Providers will be required to ensure that resources are adequately metered to enable accurate and prompt verification of delivery For resources that could inject into the local distribution network, metering capability must be two way (separately for import and export)
40	Non-market generators may be required to demonstrate their ability to: • ride through frequency excursions within defined limits • return to operation within defined timeframes from failing to ride through larger frequency excursions
41	Transpower will allow for the potential risks of DSP resource fatigue: • in evaluating individual or sets of GSC proposals • in developing its call strategy
	Design features for GSCs for voltage support only
42	Transpower as grid owner may offer GSCs to ensure that adequate voltage support services are available to be called by the System Operator when required
43	Voltage support GSCs will not be offered to market generation when injecting MW Voltage support GSCs will be offered only for dynamic or static Mvars from participants where those Mvars are additional to any obligation to provide Mvars under the Code **Measurement of Mvar performance will be at one or more defined GIPs or GXPs**
	Design features for GSCs for market generation only
44	The design and operation of GSCs for market generation will assume that the market will ensure that market generation capacity is available at times of demand peak except in the case of forced (unplanned) generation outages (or generation outages that had to be planned at short notice)

#	GSC design feature
45	GSC payments for market generators will be in the form of a preparation payment The preparation payment will be in the form of a fixed payment path, set at the start of the project, but conditional on: • Key deliverables being met • Demonstrated availability of capacity at times of demand peak except in the case of forced outages (or generation outages that had to be planned at short notice) • GSC terms being transferred in case of any change in ownership The only operation payments available for GSCs for market generation is for post-contingent run-up or run-back schemes, for which availability, call and delivery payments are allowed
46	GSCs could be offered to market generators to modify their plans to meet Transpower's need for capacity, reliability, timing and location
47	For market generator preparation payments the GSC will fund up to (but not exceeding) the actual, incremental cost of the modification
48	For market generation that is not yet commissioned, GSCs will be offered only for generation plant that is committed, in accordance with the criteria of the CapexIM GSCs that include investments will be required to provide progress reports and maintain schedules
49	Market generation GSCs will not be offered to intermittent generators • with no fuel storage (e.g. wind or solar) • with limited fuel storage (e.g. some run-of-river hydro) Limited fuel storage means not reasonably likely to have sufficient fuel storage to enable offering generation at demand peaks under all reasonably foreseeable conditions, e.g. including dry years
50	Risk management GSCs may be offered to market generation to hold fuel capacity in reserve in case of an asset failure

