TRANSPOWER

Net Zero Grid Pathways 1

Major Capex Project (Staged) Investigation

Shortlist consultation

Date: 30 June 2022

Preface

Global temperatures are rising, and we have observed more extreme weather events in recent times. These increases are attributed to global climate change, largely caused by a man-made increase in the concentration of CO2 in the atmosphere[1].

Scientists advise that the climate continues to change, that global temperatures will continue to rise, and we should expect even more extreme weather events, along with other changes such as a rise in ocean levels.

A global response is gaining momentum, with the key being to radically reduce CO2 emissions into the atmosphere and create carbon sinks to absorb some of the existing CO2 that is already there.

In April 2019 New Zealand's Interim Climate Change Committee said in their Accelerated Electrification report, "The Committee has identified accelerated electrification as a major opportunity to more rapidly reduce greenhouse gas emissions."

This response has many implications for the electricity industry, including for the transmission grid. Examples are:

- A growth in electricity demand and renewable electricity generation is expected.
- An increasing reliance on a reliable electricity supply as the proportion of electricity in our overall energy mix increases.
- Ensuring electricity supply is resilient to the many effects of climate change.

Transpower's Net Zero Grid Pathways project is aimed at ensuring the grid is fit-for-purpose and the Net Zero Grid Pathways 1 (NZGP1) Stage 1 proposal will be the first Major Capital Proposal (MCP) to be submitted to the Commerce Commission for approval, that has arisen from our investigations. Transpower has an enabling role in decarbonisation through electrification and the connection of renewable generation. The grid backbone needs to support the connection of renewable, lower cost generation as well as providing sufficient reliability to match an increasing reliance on electricity to power our economy.

In undertaking this investigation, we have used our traditional approach for dealing with future electricity demand and generation uncertainty, which is to develop and analyse scenarios. To ensure transparency in our planning, these scenarios have been developed with input from key stakeholders. This process has taken over one year, not just because of consultation, but also because we have needed to further evolve some assumptions as our landscape is changing so quickly.

Decarbonising our energy use is not just a New Zealand issue – enormous research efforts are occurring globally into various alternatives. However, the role that various energy sources such as electricity, hydrogen and biomass will play in our future energy mix is not yet clear. Regardless, forecasts including our own Whakamana I Te Mauri Hiko (WiTMH)[2] all point to a 60-80% increase in electricity demand, supported by renewable generation, by 2050. The exact nature of when and where new generation will be built, new demand will arise or when or if major electricity users might exit are unclear. However, significant binary step changes such as the closure of New Zealand's Aluminium Smelter at Tiwai Point, hydrogen for export or a commitment to Lake Onslow storage could all impact the choices for grid investment out to 2050.

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[1] NIWA, Climate change: the science, from: https://niwa.co.nz/education-and-training/schools/students/climate-change/climate-change-the-science

[2] https://www.transpower.co.nz/resources/whakamana-i-te-mauri-hiko-empowering-our-energy-future

This level of uncertainty is unparalleled and makes it clear that developing the grid flexibly to cope with as many futures as possible, is crucial to it being fit-for-purpose.

This proposed NZGP1 Stage 1 MCP seeks to ensure the grid backbone is able to accommodate renewables to 2035. We have evaluated the need and benefits of grid investments over a significant portion of the grid to ensure we better capture the combined benefits of investments in three discrete areas – the High Voltage Direct Current (HVDC) link, the Central North Island, and the Wairakei Ring. The low regrets investments we are seeking approval for are either upgrades to existing transmission lines or measures to release more capacity from the existing grid backbone. These can be deployed within two to five years and provide immediate market benefits and certainty for generation developers.

Subject to consultation feedback on this shortlist and the option selected as our first stage of a multi-staged proposal to the Commerce Commission, we are proposing a mix of shorter-medium term low regrets investments coupled with a commitment to further investigate and undertake early planning for more significant upgrades that are likely to be viable. An indicative cost of our current preferred option is ca $350m[3] including Stage 1 works, other minor required enabling investments, plus the investigations into longer term projects. Approval for the longer-term projects would be sought under subsequent stages of NZGP1.

Process to date

Investments in new interconnection assets over $20 million require MCP approval from the Commerce Commission. For these, Transpower applies the Investment Test, as prescribed under the Capex Input Methodology (Capex IM), which is a cost-benefit analysis that identifies the option with the highest long-term net benefit to electricity consumers. Under the Capex IM, we are required to submit an application to the Commerce Commission if we want to recover the full costs of an MCP from our customers. This document is intended to meet the requirements of a shortlist consultation, as described in section I3 of Schedule I of the Capex IM. In our application of the regulated investment test this is the first occasion we have modelled multiple interdependent investments to the extent used in this planned Major Capital Proposal.

We will take all feedback received into account as we finalise our MCP, which is to be submitted to the Commerce Commission for their consideration by the end of 2022.

[3] Not including financing and inflation adjustments

Executive Summary

Introduction

This document discusses our evaluation of options **to enable the efficient dispatch of new generation and a reliable supply for future demand growth over the interconnected grid**. It also identifies the option we currently anticipate we will nominate as our preferred option when we submit a Major Capex Proposal (staged) to the Commerce Commission later this year.

This investigation is part of our Net Zero Grid Pathways (NZGP) programme, which aims to support New Zealand's pathway towards greater renewable electricity generation and the electrification of our energy consumption in our pursuit of being net-zero carbon by 2050.

We seek feedback on our shortlist of options to meet the need, our approach to identifying a preferred option, and the preferred option itself.

Background

Electricity demand will increase as we transition away from fossil-fuel based energy consumption. Electricity generation will increase to meet this growth in demand and at the same time our fossil-fuelled generation will be increasingly replaced by renewables (hydro, geothermal, wind and solar).

Transpower plays a key role in enabling a future powered by renewable electricity by ensuring parties can connect to the transmission grid where and when they want and our NZGP investigation is focused on this enabling role.

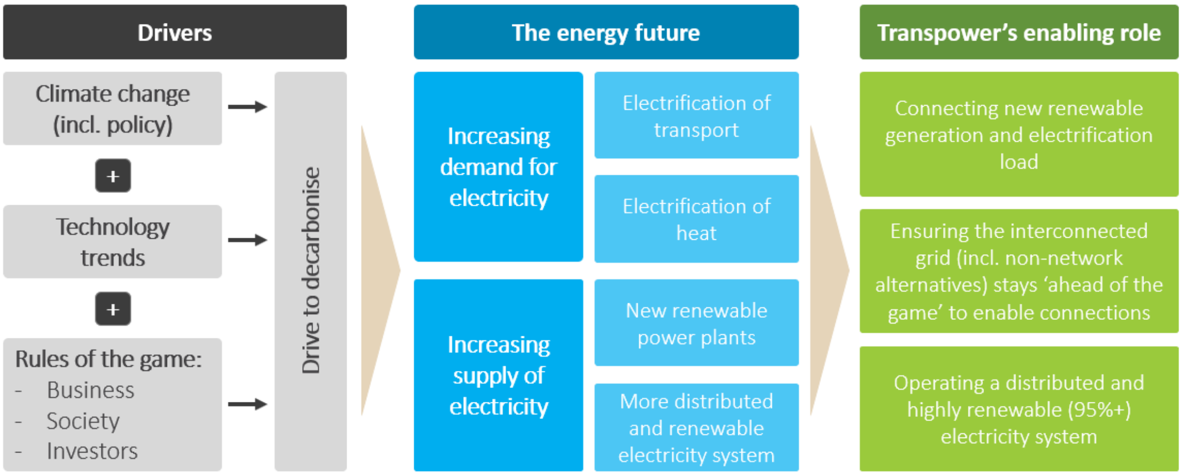

Figure 1: Transpower's enabling role in support of New Zealand pursuing net-zero carbon by 2050

We are undertaking the investigation in two phases; NZGP Phase 1 or NZGP1; focused on the timeframe to 2035 and primarily considers enhancing the grid backbone, either through upgrades to existing routes or where justified, new transmission lines[4]. These low-regrets investments for upgrades to existing transmission lines or measures to release more capacity from the existing grid backbone, can be deployed within two to five years and provide immediate market benefits and certainty for generation developers.

[4] We use the term grid backbone, rather than core grid, on purpose. Although similar, "core grid" has a very specific and slightly different meaning under the Electricity Industry Participation Code (EIPC).

There are two main approaches to relieving the overall constraints. One is to consider new transmission options which largely bypass the existing grid between the top of the South Island and Whakamaru (including the Wairakei Ring) and the second is to consider upgrading parts of the existing grid. Given the time required to identify, select and consent new transmission line routes of up to 10 years there will be a significant disbenefit if we only consider new transmission options. Our NZGP approach is therefore two-fold, with a focus on upgrading the existing grid where practicable, ahead of new transmission.

The existing grid between Haywards and Bunnythorpe does not constrain over our time horizon and is already matched in transmission capacity to proposed enhancement to the Cook Strait HVDC capacity. Cook Strait cable capacity, the grid between Bunnythorpe and Whakamaru, including the grid around the Wairakei Ring, all constrain as new generation is developed, but are likely to reach their limits at different years in the future. Our investigation has considered the work required to these parts of the grid individually, but our analysis considers them collectively, their interdependency and ability to capture the investment benefits across interdependent upgrade projects.

This proposal also includes investment in further investigation and early planning of additional major grid upgrades. This enables Transpower to advance its response to large binary step-changes in generation and demand, should they occur. The approval of these major investments, as subsequent stages of NZGP1, will allow investments to be assessed under updated electricity demand and generation scenarios (EDGS). These updated scenarios, due in 2023, should provide more certainty on the generation and electrification pathways than those available at present, which were developed from work done by the Ministry of Business, Innovation and Employment (MBIE) in 2019.

As well as further stages of NZGP1, we will also commence industry engagement on NZGP Phase 2 or NZGP2 in 2023. This work will look out to 2050 to identify how the grid backbone and regional interconnections need to develop to provide the required reliability and resilience.

The output from the NZGP project (both Phases 1 and 2) will be a long-term transmission plan, showing how we envisage the transmission system being developed between now and 2050. This plan will provide important information for electricity demand and generation investors giving guidance on future transmission capacity.

In order to navigate this document more effectively, the following diagram has been produced to highlight potential sections of interest to the reader.

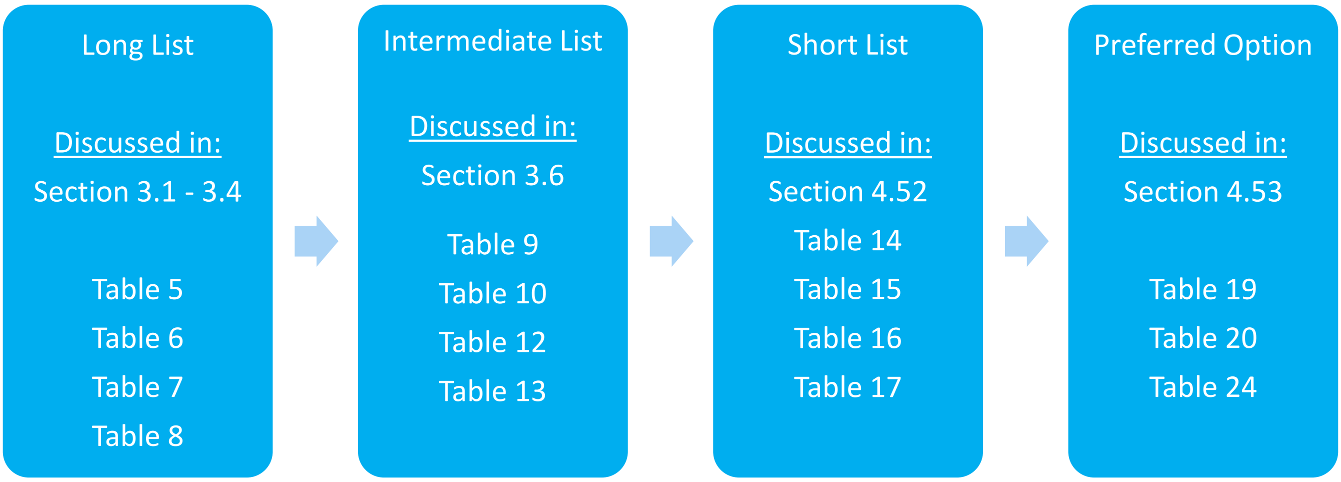

Figure 2: Document layout

Long-list consultation

We consulted on a long-list of options in August 2021[5]. That document was:

- a consultation with interested parties on the key assumptions to be used in the investigation
- a draft long-list of options to address the need for investment
- a request for information (RFI) for non-transmission solutions (NTS), which could defer or replace the need for investment in transmission.

We are calling this MCP investigation NZGP1 Stage 1, because it is likely that additional grid investment needs, potentially requiring further investigation through MCPs, will be identified as the overall NZGP programme progresses.

Our preferred option

Our long list of options included both short-term solutions, implemented relatively quickly and providing enhanced transmission capacity for up to 10 years, as well as long-term solutions, which may take longer to implement but provide more enhanced transmission capacity. Any proposal to the Commerce Commission may include a mixture of short-term and long-term solutions. For that reason, this is a staged MCP, with funding approval sought for shorter term initiatives, minor supporting facilitating projects, plus funding requested to investigate further longer term and larger investments. Apart from being relatively quick to implement, the short-term solutions may include least-regret options, deferring higher levels of capital to buy us time for uncertainties to play out, or at least enable deferment of the need to commit capital. Approval for the larger and longer-term grid investments will be sought as subsequent stages of NZGP1, when scope and cost is more certain.

[5] Link to NZGP1 Long-list Consultation

The staging projects investigated for this MCP and as notified to the Commerce Commission, are:

- HVDC capacity
- Central North Island capacity; and
- Wairakei Ring capacity

Staging project	**Stage 1**		**Stage 2 or later**	
	Preferred option	Approx. commissioning	Preferred option	Approx. commissioning
HVDC	Install new reactive plant at Haywards	2026	Add Cook Strait cable capacity	Late 2027
Central North Island	TTU Tokaanu-Whakamaru lines Duplex Tokaanu-Whakamaru lines TTU Bunnythorpe-Tokaanu lines	2023 2025 2026		
Wairakei Ring	TTU Wairakei-Whakamaru C line	2024		

Table 1: Preferred option for NZGP1

This MCP is for NZGP1 Stage 1 and will seek approval for funding of these Stage 1 projects and the related minor facilitating projects (Table 2 below). It will also seek funding to investigate those that may be constructed in Stage 2 or NZGP2. Note that our Stage 2 MCP may not include all those components listed. Our analysis currently indicates we should prioritise longer term works for the HVDC and the Wairakei Ring, and only some of the Central North Island options for Stage 2. New lines for the Central North Island could be deferred to a Stage 3 MCP.

The role of the HVDC is changing. Our Stage 1 investment will improve availability of existing HVDC equipment, an effective increase in HVDC capacity, while Stage 2 will increase the transfer capacity overall. Even if our analysis of the sensitivity to Tiwai Smelter shows that some investments could occur later we may still seek approval to expand the capacity of the HVDC earlier – this will provide flexibility to investors and maximise competition benefits.

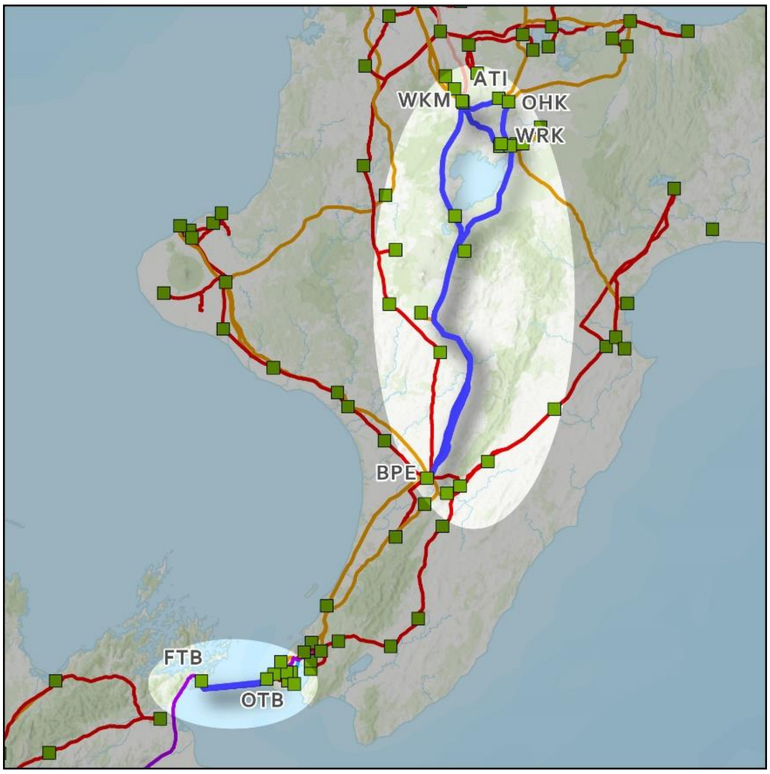

Figure 3: HVDC, Central North Island and Wairakei Assets

A list of the facilitating projects and funding to continue investigating the Stage 2 or later projects is summarised in Table 2. Justification for including these in our MCP Stage 1 is provided in section 4.

Facilitating projects	**Approx. commissioning**	**MCP Stage**
Split Bunnythorpe-Ongarue 110 kV line at Ongarue	2024	1
Replace protection on the Huntly-Stratford 220 kV line	2024	1
Split Edgecumbe-Kawerau 110 kV line	2023	1
Tactical Thermal Upgrade (TTU) Edgecumbe-Kawerau line	2025	1
Replace TKU SPS	2025	1
Reconductor Brunswick -Stratford 220 kV A line	2030	2
Preparedness projects	**Approx. completion**	
Prepare detailed designs for duplexing BPE-TKU A&B line	2023	1
Prepare detailed design for TTU of BPE-WRK A line	2023	1
Investigate routes and detailed design for new BPE north 220 kV line	2024	1

Investigate routes and detailed design for new WRK-WKM line, or replacement of existing WRK-WKM A line	2024	1
Quantifying resilience	2023	1
Funding to further investigate potential Stage 2 projects	**Approx. completion**	
Lower NI voltage stability study	2023	1
Diversification of Bunnythorpe substation	2023	1

Table 2: Facilitating projects for NZGP1

The grid outputs that we currently plan to seek approval for as our preferred option are a combination of projects from both Tables 1 and 2.

Preferred grid outputs

- Design, procure, install, and commission new reactive plant to support the HVDC at Transpower's Haywards substation
- Design, install and commission a TTU on Transpower's 220 kV Tokaanu-Whakamaru A&B lines
- Design, install, and commission duplexing on Transpower's 220 kV Tokaanu-Whakamaru A&B lines
- Design, install and commission a TTU on Transpower's 220 kV Bunnythorpe-Tokaanu A&B lines
- Design, install and commission a TTU on Transpower's 220 kV Wairakei-Whakamaru C line
- Design, install and commission a system split on Transpower's 110 kV Bunnythorpe-Ongarue 110 kV line at Ongarue
- Design, install and commission a replacement for the protection of Transpower's 220 kV Bunnythorpe-Stratford line
- Replace the Special Protection Scheme at Tokaanu
- Design, install and commission a system split on Transpower's 110 kV Edgecumbe-Kawerau line at Edgecumbe
- Design, install and commission a TTU on Transpower's 220 kV Edgecumbe-Kawerau line
- Prepare detailed designs to duplex Transpower's 220kV Bunnythorpe-Tokaanu A&B lines
- Prepare detailed design to TTU Transpower's 220 kV Bunnythorpe-Wairakei A line
- Investigate options and routes plus progress detailed design for a new 220 kV line north of Bunnythorpe
- Investigate options and routes plus progress detailed design to either replace Transpower's 220 kV Wairakei-Whakamaru A line or build a new 220 kV Wairakei-Whakamaru D line
- Investigate methodologies for quantifying resilience benefits
- Undertake an investigation into lower North Island voltage stability including recommendations for any voltage support investment required
- Investigate the potential benefits and high-level cost, of diversifying Bunnythorpe substation.

From our industry consultation on demand and generation scenarios in late 2020, we identified that the existing grid backbone across Cook Strait and as far north as Whakamaru (including the Wairakei Ring), is likely to constrain first as electricity demand and generation grows.

Our analysis showed that capacity across Cook Strait (the High Voltage Direct Current (HVDC) link between the North Island and South Island), the Central North Island 220 kV grid between Bunnythorpe and Whakamaru (CNI) and the 220 kV grid around the Wairakei Ring all constrain at similar times[6].

Recognising that the cost of relieving these constraints will exceed $20 million, we are undertaking this investigation consistent with the requirements for a Major Capex Project (staged) (MCP), as defined by the Commerce Commission in their Capital Expenditure Input Methodology (Capex IM)[7].

The investment need is to **enable the efficient dispatch of new generation and reliable supply of future demand growth over the interconnected grid**.

Preliminary costs

The preliminary costs for this MCP are below. Our costing approach to date is discussed further in section 4.45. These costs will be further refined prior to any MCP application.

Stage 1 Capital Projects	
Central North Island	$182 million
HVDC	$128 million
Wairakei	$13 million
Facilitating Projects	**$11 million**
Preparedness Projects	**$7.5 million**
Further Investigations	**$0.5 million**
Total	**$342 million**

Demand and generation forecasts

We have used demand forecasts and generation scenarios that are based on the current Electricity Demand and Generation Scenarios (EDGS) developed by the Ministry of Business, Innovation and Employment (MBIE). Our scenarios are variations of the EDGS, to ensure the scenarios are up to date, are relevant to the regions of interest and reflect the latest information about likely new generation projects.

We began developing EDGS variations in 2020 and a summary document describing our variations was published in December 2021[8].

[6] Some parts of the 110kV network in the lower and central North Island also constrain. These will be dealt with separately and are assumed to be in place for the purposes of this investigation.
[7] Consolidated Transpower capital expenditure input methodology determination as at 1 June 2018
[8] Link to NZGP1 Scenarios Update

Non-transmission solutions

Transpower is committed to exploring the application of non-transmission solutions (NTS) to replace, defer, or enable transmission investment, where economically feasible. Our NZGP1 long-list consultation posed a number of questions regarding how NTS could be incorporated into the development plans created by NZGP1.

We received limited responses and of the responses received, there were none that appeared sufficient to meet the investment need.

We have since formed a view that due to the size and breadth of the grid backbone it is unlikely a NTS would be a viable alternative to the projects covered in this MCP. However, NTS may be able to help manage operational risk due to unavailability of grid assets during a major capex project and we will explore opportunities for this once they are known.

This consultation

This consultation document is available on our website: www.Transpower.co.nz/NZGP and once this consultation has closed, we will:

- Publish the submissions on www.transpower.co.nz/NZGP. Unless otherwise requested by you, we will include both your name and your full submission on the website.
- Consider the feedback received in submissions.
- Undertake the NTS consultation as described above.
- Identify whether there is an option which passes the Investment Test.
- If applicable, submit an MCP application to the Commerce Commission before the end of 2022, which may or may not be subject to undertaking an RFP for NTS.

Your feedback

We seek written feedback by 5pm 15 August 2022. Responses should be in electronic form, in either Microsoft Word or PDF format, and emailed to nzgp@transpower.co.nz.

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.

A number of questions are asked throughout this document, and these are summarised below. These 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.

Transpower expects to publish, by 14 July, a supporting document to this consultation paper that presents indicative covered cost for NZGP1, and indicative benefit-based regional allocations that we have calculated under the new transmission pricing methodology (TPM). This supporting document aims to assist stakeholders to understand the possible impact of the preferred NZGP1 option on transmission charges across regions.

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

No.	Question	Relevant section
1	Do you agree with our staged approach to this major capital investment programme?	**1.2**
2	Is our approach to NTS reasonable?	**2.2**
3	Is our reduced list of options for enhancing capacity of the HVDC reasonable?	**3.2**
4	Is our reduced list of options for enhancing capacity of the CNI 220 kV corridor reasonable?	**3.3**
5	Is our reduced list of options for enhancing capacity of the Wairakei Ring reasonable?	**3.4**
6	Are our scenario weighting sets reasonable?	**4.31**
7	Is our shortlist of HVDC and CNI options reasonable?	**4.52**
8	Is our shortlist of Wairakei Ring options reasonable?	**4.53**
9	Is our choice of the preferred option reasonable?	**4.56**
10	Is our conclusion that upgrading existing assets is more economic than bypassing the existing grid reasonable?	**4.55**
11	Do you agree that our choice of preferred option is robust against sensitivity analysis?	**4.6**

Table 3: Consultation questions

Contents

1.0 Need for investment

1.1 Existing system

Net Zero Grid Pathways (NZGP) Phase 1 is focused on identifying and investigating potential constraints on the grid backbone to enable the efficient dispatch of new generation and reliable supply of future demand growth over the interconnected grid, for the period out to 2035. This is our investment need.

In December 2020, we undertook work[9] to consider the effect of Rio Tinto's announcement to wind-down, and eventually close, the Tiwai Point aluminium smelter (Tiwai) on the transmission system. That study identified transmission constraints on the High Voltage Direct Current (HVDC) link and the North Island 220 kV Alternating Current (AC) network between Bunnythorpe and Whakamaru (otherwise called the Central North Island or CNI) as being the most restrictive, and relieving them would provide the highest benefit to consumers. Although Tiwai closure has now been deferred, it will still have a significant effect when it does occur, and we need to be as prepared as possible.

Our consultation and studies also indicate that approximately 60-70% of future new generation will be built south of Whakamaru or be connected to our Wairakei Ring 220 kV network.

Therefore, we are investigating the transmission constraints identified in our December 2020 work in this investigation, along with the Wairakei Ring. Together, we believe these areas of the grid backbone are the most likely to constrain prior to 2035.

Our main focus has been on investigating thermal constraints on the grid backbone, because the lead-time to relieve such constraints is the longest. Particularly as parts of the grid become more highly loaded, voltage and other power quality constraints can also emerge. These are being studied separately and our MCP will include a request for funding to further these studies, as any investment required may be included in Stage 2 of this MCP. The lead-time to relieve such constraints is generally much shorter.

[9] Accessing Lower South Island Renewables December 2020.pdf

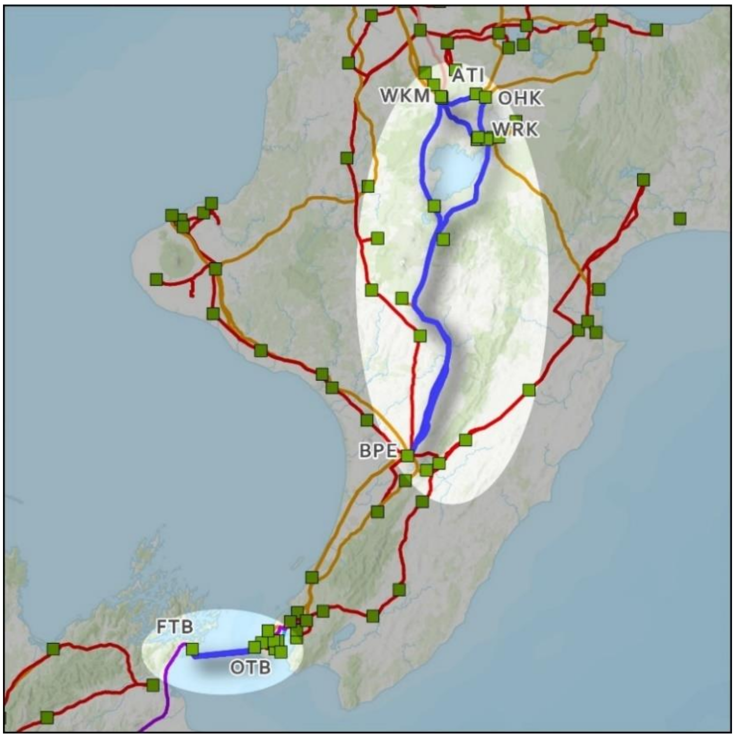

Figure 4: The existing transmission network between the top of the South Island and Whakamaru, including the Wairakei Ring

Our investigation has considered a single solution for this part of the entire network, as well as upgrading individual parts of the existing grid. With an expectation that upgrading individual parts of the existing grid may be the most beneficial, we have advised the Commerce Commission (Commission) that this investigation is for a Major Capex Project (staged) (MCP). Staging any investment required, will best allow us to take a least regrets approach and commit to significant expenditure with the maximum amount of certainty. As already discussed, we have notified the Commerce Commission that we are investigating:

- HVDC capacity
- CNI capacity; and
- Wairakei Ring capacity

The rest of this section comprises a description of the HVDC link, the 220 kV transmission between Bunnythorpe and Whakamaru and the Wairakei Ring. These descriptions are abbreviated, and more information can be found in our Transmission Planning Report[10].

The HVDC link is a key component of the New Zealand transmission network. The existing HVDC link is comprised of:

- Two ± 350 kV thyristor bipole converters, Pole 2 and 3, both rated at 700 MW, with converter stations and protection and control systems at our Benmore substation in the South Island and Haywards substation in the North Island.
- Two 350 kV bipolar transmission lines. These comprise a 535 km length from Benmore to Ōraumoa/Fighting Bay (on the shore of Cook Strait in the South Island) and a 37 km length from Oteranga Bay (on the shore of Cook Strait in the North Island), to Haywards.
- Three 350 kV, 500 MW, 40 km long undersea cables, with cable terminal stations at Fighting Bay and Oteranga Bay

[10] Link to the [Transmission Planning Report 2020 | Transpower]

- A land electrode at Bog Roy near Benmore in the South Island and a shore electrode at Te Hikowhenua near Haywards in the North Island
- AC filters to reduce harmonic distortion and provide static reactive support at both Benmore and Haywards
- Eight synchronous condensers and a STATCOM at Haywards to supplement the dynamic reactive support available from the AC transmission system.

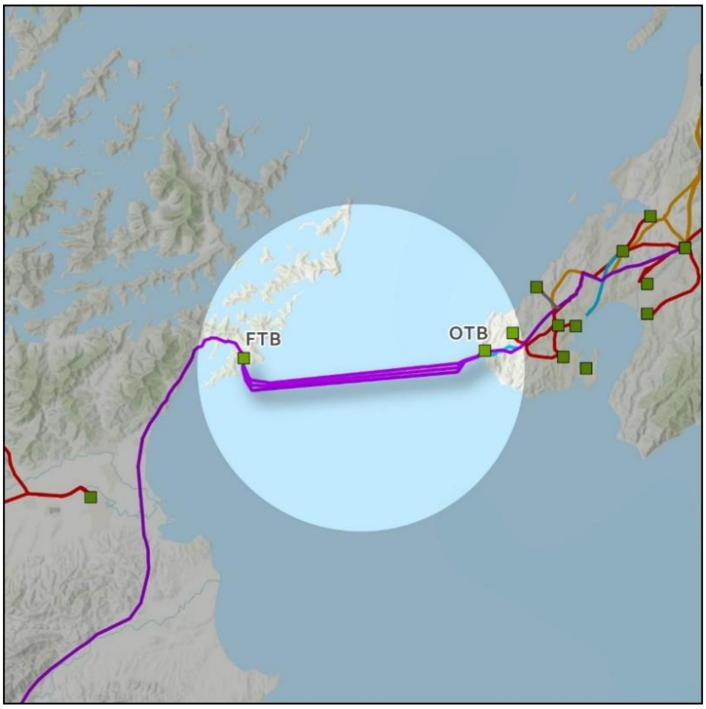

Figure 5: Geographic view of the HVDC Cook Strait link

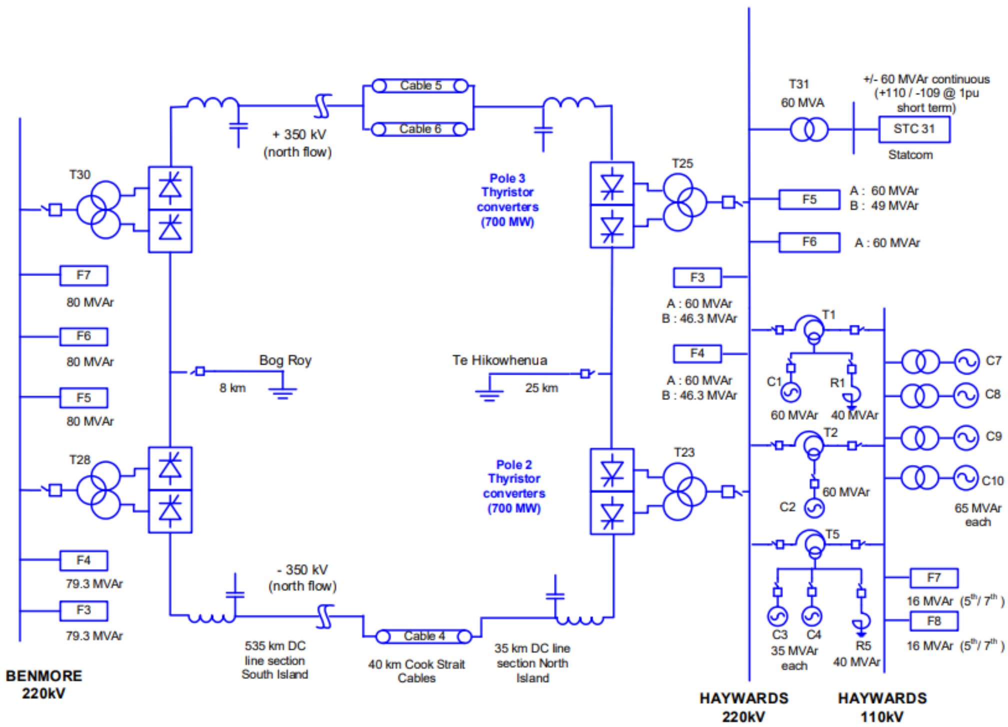

Figure 6: Simplified schematic of the existing HVDC link

1.11 Central North Island (CNI)

The CNI 220 kV transmission system consists of the 220 kV Bunnythorpe–Whakamaru A and B lines and the 220 kV Bunnythorpe–Wairakei A line.

The direction of power flow through the region, north or south, is determined by generation, direction of HVDC flow and demand outside of the region.

These 220 kV circuits form part of the grid backbone. The lower North Island also has a 110 kV network, which is mainly supplied through the 220/110 kV interconnecting transformers at our Bunnythorpe substation.

The CNI region is a main corridor for 220 kV transmission circuits through the North Island. This corridor connects the Central North Island to the Wellington region to the south, the Taranaki region to the west, the Waikato region to the north, and the Hawke's Bay region to the east.

A geographic view of the CNI is shown in Figure 7 and the single line diagram is shown in Figure 8.

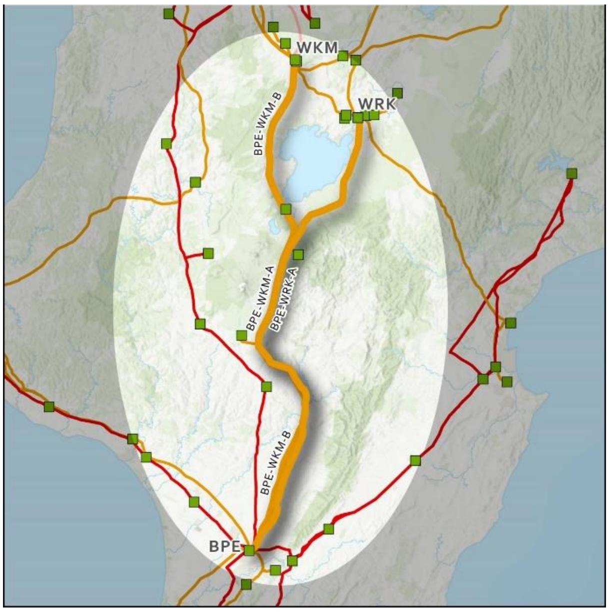

Figure 7: Geographic view of the Central North Island region transmission network

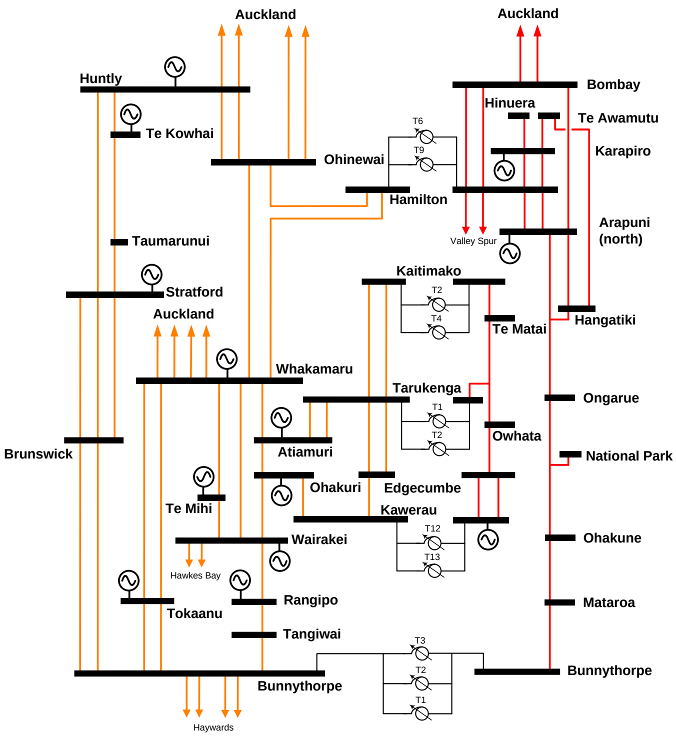

Figure 8: Single Line Diagram of the Central North Island (including Wairakei Ring) transmission network

1.12 Wairakei Ring

The so-called Wairakei Ring connects the generation rich regions of the Central North Island with the high load centres of the upper North Island, Waikato, and Bay of Plenty. The Wairakei Ring consists of two 220 kV transmission lines – the Wairakei – Whakamaru A line, which is a single circuit and the Wairakei-Whakamaru C double circuit line. The geographic layout of these lines is shown in Figure 9 and a single line diagram is included in Figure 8.

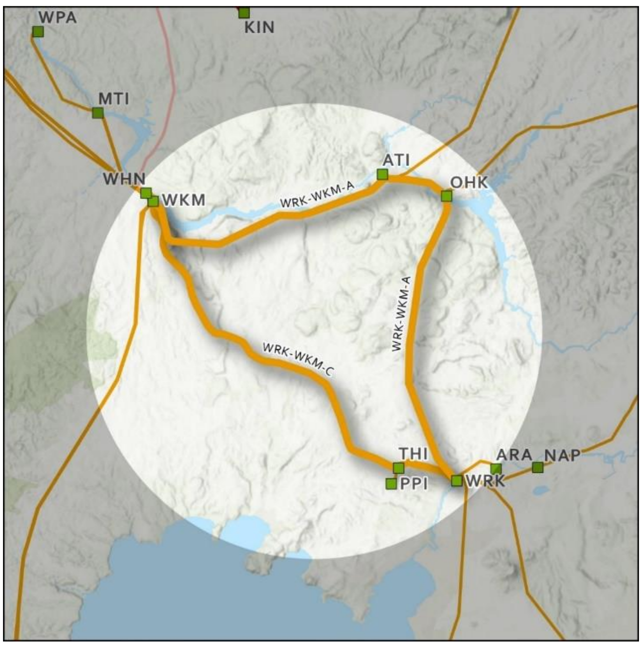

Figure 9: Geographic view of the Wairakei Ring

1.13 Other North Island constraints

Included in this section are other North Island transmission constraints which can limit north flow, from Bunnythorpe, on the backbone grid. We assume the works required to relieve these constraints have been completed in our analysis, such that they are no longer constraints on flows north of Bunnythorpe or on the Wairakei Ring. The projects to relieve these constraints are required to realise the benefits of our proposed upgrades and are termed ‘facilitating projects’.

Their cost is included in our analysis and will also be included in our NZGP1 MCP submission, should it progress that far.

Most of these facilitating projects are low cost, with the exception being Brunswick – Stratford, which for the sake of our analysis we have assumed will cost $75 million. Given the work for this facilitating project does not need to be completed until 2030, its cost will be included in a Stage 2, or later MCP. This would align with greater certainty on renewable generation investments in the Taranaki region, including offshore wind.

110 kV constraints

Before the North Island 220 kV grid was built, mostly in the 1950’s and 1960’s, the national grid consisted of a 110 kV network. When the 220 kV grid was built it was integrated with the 110 kV grid and now some parts of the older grid may constrain flows on the 220 kV grid.

In the lower North Island, the Bunnythorpe-Mataroa and Masterton-Mangamaire 110 kV circuits can constrain the 220 kV grid when flows are high. We plan to install any equipment required north of Bunnythorpe, to ensure the 110 kV grid does not constrain any of our 220 kV investments. Such equipment is already in place for a split on the Masterton–Mangamaire circuit, but not on the Bunnythorpe–Mataroa circuit.

Huntly-Stratford protection limit

As well as the CNI 220 kV lines heading north from Bunnythorpe, there is also a 220 kV route which goes from Bunnythorpe to Brunswick, then on to Stratford and finally on to Huntly. The Huntly-Stratford portion of this line constrains in some circumstances, with the frequency and severity depending upon generation within the Taranaki region.

The announced retirement of the Stratford combined cycle generator in 2024 will reduce the frequency of this constraint, but it still constrains at times. Options such as re-building the line and enhancing the capacity are possible, although expensive. At least for the short term, there is an option to change the protection limit on this line. This will require new protection equipment, but at a fraction of the cost to upgrade the line itself.

Tokaanu SPS

The existing Tokaanu SPS monitors the two Tokaanu-Whakamaru circuits and splits the Tokaanu 220 kV bus when it detects the outage of one of the circuits. The scheme results in power flow from Bunnythorpe towards the upper North Island to be redistributed to other transmission paths to relieve the loading on the constraining Tokaanu–Whakamaru circuit.

Once the Tokaanu–Whakamaru circuits are upgraded, the constraint will be on the Bunnythorpe–Tokaanu circuits and upgrading the Tokaanu SPS to also split the Tokaanu 220 kV bus following a Bunnythorpe–Tokaanu circuit outage will have a similar effect on relieving the loading on the remaining Bunnythorpe–Tokaanu circuit.

Brunswick – Stratford 220 kV

Similarly, the Brunswick – Stratford section of the Bunnythorpe to Huntly 220 kV route can also constrain flows north from Bunnythorpe.

This part of the route consists of two lines, with one line nearing end-of-life. A plan has yet to be formulated for Brunswick – Stratford, with options ranging from replacing the old line to dismantling the old line and upgrading the newer line.

In our analysis we assume the Brunswick-Stratford constraint is relieved by 2030.

Edgecumbe – Kawerau 110kV line

Presently there are two special protection schemes that manage post-contingency overloading on the 110 kV Edgecumbe-Owhata and Edgecumbe-Kawerau lines. With the expected increase in western Bay of Plenty load and eastern Bay of Plenty generation, the Edgecumbe-Owhata line can overload pre-contingency. Splitting Edgecumbe-Kawerau will avoid the need for pre-contingency generation constraints and free up capacity for additional generation.

Edgecumbe – Kawerau 220kV line

The 220 kV Edgecumbe-Kawerau 3 circuit is effectively in parallel with the Wairakei Ring circuits. Under some generation dispatch patterns this circuit becomes the first constraint for high power transfer through the Wairakei Ring. A thermal uprating of this circuit is required to make full use of the proposed Wairakei Ring upgrades.

1.2 Overview of the need for investigation and investment

Irrespective of Tiwai closure, as New Zealand pursues its net zero carbon by 2050 goal, electricity demand will grow as electrification occurs and new renewable generation will be built. As this occurs a number of constraints will emerge on the transmission grid between the top of the South Island and Whakamaru (including the Wairakei Ring).

Relieving these constraints would provide confidence to generation investors that new generation could be economically dispatched and hence ensure the generation investment market remains competitive.

We could build a new connection between these parts of the network, or enhance parts of the existing network – the HVDC, our CNI 220 kV network and the Wairakei Ring.

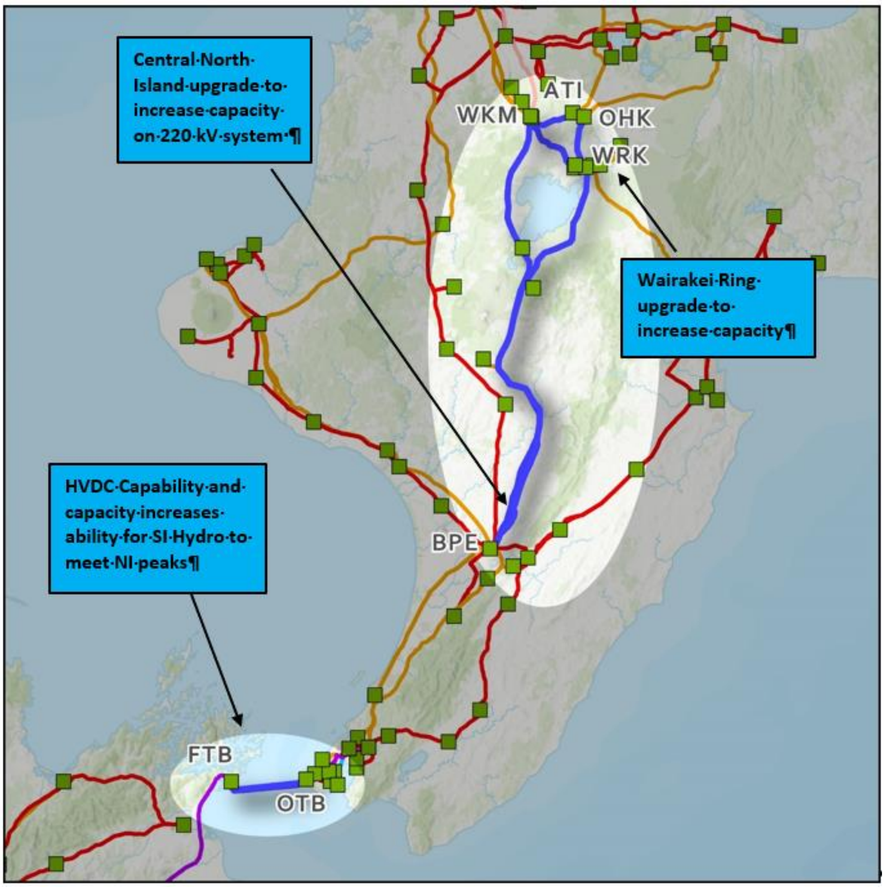

Figure 10: Initiatives being investigated in NZGP1

1.21 HVDC capacity

The nominal rating of the Pole 2 and Pole 3 HVDC converters is 700 MW each. However, we only have three 500 MW cables across Cook Strait. Two are connected to Pole 3 and one is connected to Pole2. This means the nominal end-to-end capacity of Pole 2 is limited to 500 MW and the combined HVDC capacity is limited to 1200 MW.

In total, the HVDC link between the North and South Islands therefore has a capacity of up to 1000 MW in balanced 500/500 MW bipole operation and up to 1200 MW[11] in unbalanced 500/700 MW bipole operation. The ability to run in unbalanced mode depends upon the availability of instantaneous reserves, as this mode requires more reserves to be purchased.

These are north flow capacities, with south flow being limited to 850 MW.

Other factors also affect the north flow capacity – in particular the availability of ancillary equipment at Haywards and surrounding AC transmission. There are eight synchronous condensers at Haywards which provide voltage support to the HVDC. These are large mechanical rotating machines and by their nature require frequent maintenance. If any one machine is out of service for maintenance, the HVDC north flow limit is reduced. Similarly, the AC lines between Haywards and Bunnythorpe are all required. These lines are taken out of service from time-to-time for maintenance and this also reduces the north flow limit. A recent historical analysis found that, over the last 5 years, the average north flow capability has been 1071 MW, taking account of actual ancillary equipment and AC line outages.

Historically, the HVDC was installed to transfer electricity produced from South Island hydro to the North Island. The North Island had adequate thermal generation to be self-sufficient in terms of electricity supply, so it was not overly important when electricity from the south was dispatched north, provided it was.

Our studies indicate that the role of the HVDC link in the New Zealand power system, is likely to change. Wind and solar generation is intermittent. Electricity from wind generation is only available if the wind is blowing and electricity from solar generation is only available if the sun is shining. Other forms of generation are required to “firm” such intermittent generation. Currently, as wind and solar generation grows in the North Island, it can be firmed by hydro generation in the North Island and peaking gas fired generation. However, as gas fired generation is closed and more North Island wind and solar generation is built, it will start to be firmed using South Island hydro generation. Eventually South Island hydro will be critical to real-time operation of North Island load and availability of the HVDC will play a critical role in that operation.

Our investigation has considered not only options for increasing HVDC Cook Strait capacity, but also options to lift the availability of that capacity.

1.22 CNI 220 kV

North flow transmission through the CNI region is close to being constrained at times and if any significant new generation south of Bunnythorpe emerged, we would likely see significant constraints. Tiwai Point smelter closure, for instance, would result in significant constraints.

Previous analysis indicates that the two Tokaanu – Whakamaru 220 kV circuits can constrain north flow through the CNI region in various scenarios. If constraints are removed on these circuits via upgrade work, then the two Bunnythorpe – Tokaanu 220 kV circuits would then become the limiting constraint.

Our investigation has considered options to increase flows through the CNI, including thermal upgrades of existing lines through to building a new line altogether.

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[11] Although maximum transfer capability of the HVDC assets is continuously available (not withstanding outages), the maximum energy transfer achieved at any point in time is dependent on market energy and reserve offers, and the capacity of the surrounding AC networks in the North and South Islands to supply regional loads and support both AC and HVDC energy transfer requirements.

1.23 Wairakei Ring

The capacity of the Wairakei – Whakamaru line and Wairakei–Ohakuri–Atiamuri–Whakamaru line may cause a transmission constraint during high generation in the Wairakei Ring, eastern Bay of Plenty or Hawkes Bay areas. This constraint would be exacerbated if there is a reduction in industrial load in the Bay of Plenty region, or if additional generation is developed around the Wairakei, Bay of Plenty, or Hawkes Bay regions. High through transmission on the CNI lines north to Whakamaru can also exacerbate the Wairakei Ring constraint, but to much less extent.

Thermal uprating is possible on the Wairakei – Whakamaru line, but not on the Wairakei–Ohakuri–Atiamuri–Whakamaru line. As part of our investigations, we will assume the series reactor on the Wairakei–Ohakuri–Atiamuri– Whakamaru line (to balance flows on the Wairakei Ring circuits), has been installed, but then that all short-term, low cost options have been exhausted.

Our investigation has focussed on thermal uprating of the Wairakei – Whakamaru line, duplexing the single circuit Wairakei–Ohakuri–Atiamuri–Whakamaru line and new line options.

Q1. Do you agree with our staged approach to this major capital investment programme?

1.3 Relevant asset condition issues

1.31 Condition of Pole 2 Equipment and HVDC Cables

The Pole 2 converters and three Cook Strait cables were commissioned in 1991 and have performed very well to date. The converter transformers and valves are generally in good order and another 25 years of service is to be expected if critical items are refurbished at this half-life point in their lifecycle. Preparations are now in progress for these refurbishments during the remainder of Regulatory Control Period 3 (RCP3) and RCP4.

Pole 2 control systems which have a shorter (20 year) lifecycle due to obsolescence were replaced during the Pole 3 project in 2012.

Critical Valve Base Electronics equipment (part of the control system) not able to be replaced during the Pole3 project was replaced in 2020 along with all snubber capacitor assemblies within the valves.

With these refurbishments, we expect Pole 2 will last well beyond 2040.

The three Cook Strait submarine cables which have a 40-year design life, are anticipated to reach the end of their design life in approximately 2032.

The Cook Strait environment is one of the worlds harshest for submarine cables, with extreme tidal flows. In general, the condition of the protective outer layer of the Cook Strait cables remains sound, however in localized places the outer protective layer has worn through exposing the underlying layers. Remedial works are used wherever possible, but we expect the effects of constant abrasion and corrosion of the protective outer layers will ultimately determine timing for cable end of life.

A study is underway into the replacement of existing cables. It may be that if installation of a fourth cable, to lift HVDC transfer north capacity to 1400 MW, is economic, it could be undertaken at the same time, or it may be economic to install a fourth cable sooner and bring replacement of the other cables forward. All such options are being considered. Replacement of the existing cables will be funded through an alternate means, to be agreed separately with the Commerce Commission.

1.32 Condition of CNI and Wairakei Ring lines

The most relevant condition issue for both the CNI and Wairakei Ring sections of the backbone grid are the condition of the conductors and when they would otherwise be replaced.

In some options future maintenance (conductor replacement) may be avoided.

The following table summarises the assumptions used in our NZGP1 analysis.

Line	End of life range	NZGP1 end of life assumption
Bunnythorpe – Whakamaru A	2034 – 2049	2042
Bunnythorpe – Whakamaru B	2034 – 2050	2042
Bunnythorpe – Wairakei A	2050 -2076	>2050
Wairakei – Whakamaru A	2037 – 2070	>2050
Wairakei – Whakamaru C	2109 - 2137	>2050

Table 4: NZGP Assumptions

2.0 Regulatory process for the approval of investments expected to cost more than $20 million

2.1 Regulatory Process

Should this investigation determine that the preferred option is to enhance the service provision of the existing grid and the cost will exceed $20 million, we will submit a MCP to the Commission, in order to recover the costs of the project from transmission customers. Commission approval will allow us to either recover the costs as operating expenditure should the investment be a recoverable cost, or to include the investment on our regulated asset base and recover the cost through the Transmission Pricing Methodology (TPM).

On 12 April 2022, the Electricity Authority announced its decision to adopt a new TPM. Transpower is now working to implement the new TPM into prices that will take effect from 1 April 2023.

A key component of the new TPM is a benefit-based charge (BBC) to recover the costs of post-2019 grid investments, and seven historical grid investments. The BBC aims to allocate the cost of those grid investments to transmission customers, broadly in proportion to customers' positive net private benefits from those investments as expected at the time of setting the charge. For an investment that is a 'high-value investment' (over the base capex threshold in the Transpower Capex IM, a capital cost of $20 million) one of the TPM's standard methods would be used to calculate customer allocations for the investment.

To support this NZGP1 shortlist consultation, we expect to publish, by 14 July, a supporting document presenting indicative covered costs and indicative benefit-based regional allocations calculated under the new TPM for the preferred options identified from this investigation.

If this NZGP1 shortlist consultation leads to a MCP to the Commerce Commission, Transpower will consult on proposed starting customer allocations. We will aim to carry out this consultation before the Commission consults on its own draft determination.

The Commerce Commission will consider Transpower's MCP and consult on its own draft determination. Following the Commerce Commission's final determination, Transpower will then make its own final investment decision and publish the starting customer allocations. Further information on the expected timeline for consultation on proposed customer allocations will be included in the supporting document.

The process we are using for this investigation is consistent with the requirements of the Commerce Commission's Capex IM but to date, we have consulted more widely than is required by the Capex IM.

We began this investigation in 2020, notifying the Commerce Commission of our intent, in a letter dated 23 July 2021.

The Capex IM requires that we use the most recent Electricity Demand and Generation Scenarios (EDGS) in our investigation, or reasonable variations of those scenarios. We identified there had been several important changes since the last EDGS were published and reviewed the EDGS with a view to developing more up-to-date variations.

We formed a panel of external (to Transpower) experts to advise us on potential variations and through two online panel sessions[12] developed a set of variations which were published in December 2020[13] for consultation.

As a result of feedback to that consultation we undertook further consultation to help us develop our generation scenario variations.

We then published a long-list consultation document in August 2021 and a final version of the scenarios in December 2021.

Our analysis has reduced the long list of options to address the need to a shortlist and this document describes our preliminary application of the Investment Test and preferred option.

Subject to feedback to this consultation document we will prepare and submit a MCP (staged) to the Commerce Commission by the end of 2022.

As a result of our previous consultations, this document departs to some extent from our previous shortlist consultation documents in relation to relevant demand and generation scenarios. We summarise our scenario variations only, with a reference to our December 2021 document for complete detail. Although different, this approach is still consistent with the requirements of section I3 of Schedule I of the Capex IM.

2.2 Treatment of non-transmission solutions

We are also departing from our traditional approach to the consideration of non-transmission solutions (NTS).

Previously, we issued an RFI for NTS with our long-list consultation and followed up on any interest during our analysis, reporting on the outcome as a part of our Investment Test application in the shortlist consultation.

Whilst we did issue a high level RFI with our long-list consultation and received some responses, interest from proponents was mostly limited to supporting the overall concept of NTS, rather than offering specific projects or technologies that could be used to replace or defer the transmission options.

We formed a view that NTS were unlikely to be a viable substitute for transmission on the backbone grid, due to scale. The smallest increment in transmission capacity we have considered is around 200 MW, which exceeds what most NTS providers would consider and exceeds the aggregated interest shown to our long-list RFI.

However, it is difficult to take outages on the backbone grid. Flows over the backbone grid do not follow what might be observed in a regional grid, where they are consistent with electricity demand peaks and troughs. The backbone grid is the platform for operation of our electricity market and flows are dependent on operation of that market. Peak flows can even be at off-peak demand times. We consider that NTS may be most useful in helping to create or support outage windows if they are required to implement our preferred upgrade option.

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12 Link to panel discussions

13 Link to scenarios document.

Our intention is to publish this shortlist consultation document, assess the feedback and then decide whether and when to investigate NTS further.

We say whether, because if our preferred option changes, as a result of consultation, to building new lines, then it is unlikely NTS would be useful. On the other hand, if our preferred option remains as described in this document and includes reconductoring of our existing lines, which require extensive outages, then NTS may be useful and economic.

We say when, because our experience to date has been that NTS proponents are reluctant to offer services to Transpower if the need for those services is too far into the future. The process we follow is a regulatory requirement, but it was developed when we had no experience with NTS. If NTS are relevant, it would likely be better to seek Commission approval for a project without NTS, but with an undertaking to explore the use of NTS at the relevant time.

Q2. Is our approach to NTS reasonable?

3.0 Long-list of options

This section describes several long lists of options.

Table 5 includes the first long list, which are options to bypass the existing grid and not upgrade it. Two options are included.

The first utilises the existing HVDC assets to their maximum capacity of 1400 MW as far as Haywards. At Haywards, 700 MW is converted to AC and injected into the AC grid, while a new HVDC line is built to Whakamaru, where a new 700 MW converter is installed.

The second option reflects a new link being built entirely between the North and South Islands. Such an option might be required if a large Lake Onslow scheme is developed and it could also meet our overall need. New HVDC converters would be installed in the South Island, a new HVDC line built to the Nelson region, new undersea cables would be installed between there and the Taranaki south coast, a new HVDC line would be built with Taranaki to the west and Ruapehu to the East, as far as Huntly, where new HVDC converters would be installed.

Tables, 6, 7 and 8 are the remaining long lists of options, which include potential upgrades of the existing assets, including new assets, for the existing HVDC, CNI and Wairakei Ring successively. These are our staging projects and in each table, the right-hand column indicates whether that option has been considered further, or dismissed.

3.1 NZGP1 Long List Options

Option Type	Option sub-type	Option (duration of works)	Details	Comments	Considered further
A1	Do Nothing (Counterfactual)				YES
Transmission options - new assets					
B1	New North Island HVDC Option	**Extend the HVDC from Haywards to Whakamaru.** Requires a new HVDC line. (duration of works to be confirmed)	Enhance the Cook Strait capacity from the existing 1200 MW link to 1450 MW. Build a new (700 MW capacity) HVDC line from Haywards to Whakamaru. Retain 700 MW of HVDC converter capacity at Haywards and install a new 700 MW converter at Whakamaru.	This option would require enhancement to the existing Cook Strait cable capacity, a new line from Haywards to Whakamaru and a new 700 MW HVDC converter to be installed at Whakamaru.	YES This option would meet the overall need and avoid the need to upgrade the existing grid
B2	New inter-island HVDC option	**Install a new HVDC converter in South Island, new undersea cables from Nelson region to Taranaki region, new HVDC line to Huntly and new HVDC converter at Huntly.** Requires new assets. (duration of works to be confirmed)	Install a new HVDC converter/s (700 MW to 1400 MW) in the South Island (location depending upon application (could be in the north of the South Island, or as far south as Lake Onslow), new line to Nelson region, undersea cables to south Taranaki, new HVDC line to Huntly and new HVDC converters at Huntly.	This option would require new assets entirely but would provide resilience in supply between the North and South Islands. Such a configuration would meet the overall need, avoiding the need to upgrade the existing grid.	YES This option would meet the overall need and avoid the need to upgrade the existing grid

Table 5: Options that could potentially meet the overall need

3.2 HVDC Long List Options

Option Type	Option sub-type	Option (duration of works)	Details	Comments	Considered further
A1	Do Nothing (Counterfactual)		Keeping the existing HVDC capacity (1200 MW N / 850 MW S)	Existing HVDC Cook Strait cables will require replacement circa 2032	YES
			Non-transmission solution		
B1	Expansion	**Enhanced STATCOM**	Install enhanced STATCOM. Run the HVDC in unbalanced mode with enhanced STATCOM providing the higher reserve requirement when transfers are above 800 MW.	An enhanced STATCOM is a STATCOM with battery capability.	NO Market participants will decide if providing or purchasing higher reserves to enable an unbalanced HVDC mode is economic.
			Improve availability		
C1	Improve availability	**HAY & BEN reactive support**	Installation of reactive support devices to provide improved link availability		NO
C2	Improve availability	**HAY & BEN reactive support with redundancy**	Installation of reactive support equipment to provide improved link availability, including installation of additional devices to create redundancy. Would target to lift the historic average availability from 1071 MW to close to 1200 MW.		YES
			Expansion - fourth cable		
C1	Expansion	**Fourth Cook Strait Cable** (duration 2-5 yrs.)	Allows Pole 2 operation up to 700 MW (+200 MW). Increases Pole 2 ramp up (reserve) capacity to 700 MW (+60 MW) HVDC Target Capacity: 1200 MW N/ 850 MW S	Improves HVDC Bipole utilisation by increasing Pole 2 ramp up / overload capacity to 700 MW. Shifts threshold for dependence on NI instantaneous reserve up to 700 MW (from 640 MW).	NO Only provides small increase in capacity as an isolated option

C2	Expansion	**Fourth Cook Strait Cable with an increase Pole 2 overload capacity** (duration 2-5 yrs.)	Allows Pole 2 operation up to 700 MW (+200 MW). Increases Pole 2 ramp up (reserve) capacity to 1000 MW for 15 minutes. HVDC Target Capacity: 1200 MW N/ 850 MW S	Improves HVDC Bipole utilisation by increasing Pole 2 ramp up / overload capacity to 100 MW. Shifts threshold for dependence on NI instantaneous reserve for transfer up to 100 MW (from 64 MW). Requires replacement of some Pole 2 equipment	NO Only provides small increase in capacity as an isolated option
C3	Expansion	**Fourth Cook Strait Cable, increase Pole 2 overload capacity and additional reactive support equipment at Haywards/Benmore** (duration 2-5 yrs.)	Allows Pole 2 operation up to 700 MW (+200 MW). Increases Pole 2 ramp up (reserve) capacity to 1000 MW for 15 minutes. Increases Bipole capacity to 1400 MW N (+200 MW) and 950 MW S (+100 MW) HVDC Target Capacity: 1400 MW N / 950 MW S	Increases Bipole transfer capacity (+200 MW) Improves HVDC Bipole utilisation by increasing Pole 2 ramp up / overload capacity to 1000 MW. Shifts threshold for dependence on NI instantaneous reserve for transfer up to 1000 MW (from 640 MW). Requires replacement of some Pole 2 equipment Requires installation of reactive support equipment HAY and BEN. Requires augmentation or reconfiguration of the lower NI AC 110 kV network for increased South transfer	YES Improves Bipole capacity, reduces receiving IR requirements, improves equipment redundancy levels
C4	New additional HVDC link (duration to be confirmed)	**New Pole 700 MW N/ 500 MW S** (duration to be confirmed)	Total HVDC Target Capacity: 2100 MW N / 1550 MW S	Some scenarios (Onslow and/or significant increased SI demand) show a requirement for additional 700 MW N / 700 MW S. (Total 2100 MW N / 1550 MW S) Existing assets have theoretical maximum capacity for 1480 MW N and 950 MW S. Increasing HVDC transfer capacity above 1200 MW N and 850 MW S requires additional reactive support and augmentation of the lower NI AC transmission network (to supply load in Wellington and increase HVDC transfer South. Additional link to consider converter locations in relation to AC network requirements and termination points for submarine cable/s	YES Is the same as option B2 where the existing grid is bypassed
Modify/upgrade					
D1	Incremental Improvement	**Increase HVDC Operating Current or Voltage** (duration 12-18 mths)	Increase Pole nominal operating limits approx. 10 MW (per pole). Increases Pole 2 ramp up (reserve) capacity to 650 MW (+10 MW) HVDC Target Capacity: 1200 MW N/ 850 MW S	Minor improvement to HVDC utilisation by increasing Pole 2 ramp up / overload capacity to 650 MW (+10 MW). Requires use of technology to enhance assessment of local ambient conditions. Shifts threshold for dependence on NI instantaneous reserve up by 10 MW to 650 MW.	NO This option would place strain on equipment and is not a viable long-term option

D2	Utilise Pole 2 ramp up (reserve) capacity	**Utilise Pole 2 to ramp up capacity (reserve) for energy transfer** Operational change	Allows Pole 2 dispatch to full asset capability of 500 MW for energy transfer (from 420 MW). HVDC Target Capacity: 1200 MW N/ 850 MW S	Requires additional instantaneous reserve (+130 MW) in receiving island provided by others. Increase in reserve costs (HVDC risk setter).	NO This option does not provide the required benefits, The option does not contribute to overall transfer capacity and would increase receiving island reserve requirements

Table 6: HVDC components that could potentially meet all or a part of the need. This list may contain “tactical” options, which meet the need in the short-term need, but are followed by another option to meet long-term need

Q3. Is our reduced list of options for enhancing capacity of the HVDC reasonable?

3.3 CNI 220 kV Long List Options

Option Type	Option sub-type	Option (duration of works)	Details	Comments	Considered Further
A1	Do Nothing (Counterfactual)			The need to enable efficient dispatch for new generation and reliable supply of future demand growth can’t be addressed with this option.	YES
		Non-Transmission Options			
B1	Battery Storage	**Battery installed north of constraint** (duration of works to be confirmed**)**	A battery would need to act as a generator and/or only discharge on command, requiring a SPS system to work with the battery. If it only discharges on command: a SPS would detect a Tokaanu–Whakamaru circuit overload and ramp up the output of the battery while ramping down generation south of Whakamaru.	Market impacts have not been revised, as this solution would have to be accepted by the industry participants and regulator, including the development of protection grade communications and other SPS associated investments. A battery could potentially also provide reserves for the HVDC but not voltage support.	YES Non-transmission options will be considered separately. These solutions have potential to enable outages.

B2	Generation Redispatch	**Automatic Generation Controller (AGC)** (duration of works to be confirmed)	Automatic scheme to detect overloading of Tokaanu–Whakamaru circuits and automatically and concurrently reduce demand north of Whakamaru and generation south of Whakamaru to remove the overload.	Viability depends on the level of interest from demand and generation customers to facilitate such an SPS. This is technically a lot more challenging than installing an AGC as there isn't the ability to precisely control demand like generation. If possible, this could potentially be a partial solution to defer transmission options	YES Non-transmission options will be considered separately. These solutions have potential to enable outages.
B3	Load Shedding	**Automatic scheme to concurrently reduce demand north of Whakamaru and generation south of Whakamaru post contingency to resolve grid overloads** (duration of works to be confirmed)	Regulated operation, where the load acts like a generator, allowing to minimise cost through controlled dispatch (start and stop electricity consumption) and when the load will only disconnect on instruction and remain off until the System Operator restores the grid back in a secure state.	Viability depends on the level of interest from demand and generation customers to facilitate such an SPS. This is technically a lot more challenging than installing an AGC as there isn't the ability to precisely control demand like generation. If possible, this could be a partial solution and it would require the acceptance of the market. This is technically more challenging than installing a generation redispatch SPS as demand not able to be precisely controlled.	YES Non-transmission options will be considered separately. These solutions have potential to enable outages.
Transmission options - existing assets: maintain, upgrade, enhance, modify					
C1	Bussing existing line	**Bus the three Central North Island lines at an optimal point to improve load sharing between them**. (1 year of consenting + 3 years to build)	A new switching station where the three lines run adjacent to each other to bus them between Bunnythorpe and Whakamaru/Wairakei. Bussing can be beneficial in cases where some parallel lines are underutilised as it generally improves load sharing among them.	High level load flow analysis shows there to be no benefits as all three lines are already well utilised.	NO Little benefit was found by undertaking as the circuits are already well balanced
C2	Line upgrade	**Duplexing reconductoring of existing 220 kV Bunnythorpe-Whakamaru A and B lines** (2 years consenting and planning + 4 years build]	Converting the existing simplex Goat to an uprated duplex conductor.	Duplexing both existing Bunnythorpe-Whakamaru A&B lines will require strengthening key structures and foundations throughout the line. Duplexing provides the largest thermal capacity increase for the Central North Island corridor under the Line Upgrade sub-category. It also minimises system impedance which generally improves system performance during system events. Duplexing can be split into 2 stages with: 1. Stage 1- duplexing Tokaanu–Whakamaru sections 2. Stage 2 – duplexing Bunnythorpe–Tokaanu sections	YES This option provides largest thermal capacity as an upgrade and is reasonably fast to deliver

C3	Line upgrade	**Simplex reconductoring of existing 220 kV Bunnythorpe-Whakamaru A and B lines** [2 years consenting and planning + 4 years build]	Reconductor existing simplex Goat with a larger conductor in a simplex configuration.	Reconductoring with a larger conductor would still likely require strengthening the towers and foundations, but not on the level of D2. Reconductoring with a larger conductor in simplex configuration provides some increase in thermal capacity but not to the extent of duplexing. It only provides a small reduction in system impedance which would generally improve system performance during system events. Reconductoring can be split into 2 stages with: 1. Stage 1- reconductoring Tokaanu–Whakamaru sections Stage 2 – reconductoring Bunnythorpe–Tokaanu sections	NO Does not provide as much benefit as duplexing and due to the higher conductor impedance could cause voltage stability issues
C4	Line upgrade	**HTLS reconductoring of existing lines**[14] [2 years consenting, and planning + 4 years build]	Converting the existing simplex Goat to a high-temperature low-sag (HTLS) conductor	HTLS is currently being trialled by Transpower on sections of a recently reconductored line but it's performance and deliverables are not currently verified, particularly in regions with colder temperatures (snow). The capacity gains for this option may mean that it is only a partial solution. Reconductoring with a HTLS conductor in simplex configuration may not provide material increase in thermal capacity as it is unlikely to reduce the impedance of the upgraded lines which would otherwise offload parallel lower capacity lines. It also does not materially reduce system impedance which would generally improve system performance during system events. Therefore, further studies are required to check that voltage stability limits do not limit the benefits of this option. Voltage support equipment, if required, adds cost to this option. HTLS conductors are also higher resistance therefore transmission losses will be higher. Reconductoring can be split into 2 stages, similarly to D3.	NO This option is inferior to the duplex reconductoring options

[14] HTLS is not yet approved for widespread use in the network. The information required to progress on this option is outside of the timeframe required to address the needs.

Option Type	Option sub-type	Option (duration of works)	Details	Comments	Considered further
C5	Line upgrade	**Thermally upgrading of existing 220 kV lines** (3 years to build)	Upgrade the maximum operating temperature of existing 220 kV Bunnythorpe–Whakamaru A and B lines (also known as thermal upgrade) to achieve more capacity.	Thermal upgrades could provide similar benefits to reconductoring with HTLS conductor in simplex configuration but won't be as beneficial to reconductoring with a larger conductor in simplex configuration or duplexing. Thermal upgrades do not reduce system impedance which would generally improve system performance during system events. Therefore, further studies are required to check that voltage stability limits do not limit the benefits of this option. Voltage support equipment, if required, adds cost to this option. Thermal upgrades can be split into 2 stages with: 1. Stage 1 – thermal upgrading Tokaanu–Whakamaru sections 2. Stage 2 – thermal upgrading Bunnythorpe–Tokaanu sections Thermal upgrades (one or both stages) could be a good option to defer more significant transmission upgrades	YES This option is worth exploring further due to its low cost
C6	Variable Line ratings	**Apply Variable Line Ratings (VLR) on existing 220 kV lines** (3 years to build)	Apply VLR to existing Bunnythorpe–Whakamaru and Bunnythorpe–Wairakei lines. Variable line ratings use historical weather data to provide more granular ratings depending on the time of day and year. This generally increases ratings in the mornings and evenings where ambient temperatures are typically lower.	Some lines work is required prior to the application of VLR. On the interconnected grid, capacity needs depend on the most economic dispatch of generation. Therefore, the periods where VLR provides better ratings may not coincide with periods where the market would benefit from the additional capacity.	YES VLR is a low cost option and will be combined with thermal uprating
C7	Series reactor	**Install series reactors on constraining Central North island circuits** (2 years for build + 1 year for consenting)	Install series reactors on the constraining Tokaanu–Whakamaru circuits to reduce power flowing through them. Series reactors can be beneficial in cases where some parallel lines are underutilised as it generally improves load sharing among them	Series reactors do provide a small increase in transmission capacity as it forces more power to flow north through the Taranaki region. However, the benefits are contingent on some thermal generation retirements (e.g., the Stratford combined cycle generator) in the Taranaki region to free up transmission capacity in the region.	NO Similar to option C1, circuits are already well balanced so this option would not provide additional capacity

C8	Dynamic Line Rating	**Apply dynamic line rating (DLR) on existing 220 kV lines** (2 years for build)	Apply DLR to existing Bunnythorpe–Whakamaru and Bunnythorpe–Wairakei lines. Dynamic line ratings allow line ratings to be calculated in real-time based weather condition measurements. This typically provides higher ratings for transmission lines when compared with static ratings that are calculated using assumptions that may be conservative for a large portion of the time.	Requires investments in weather monitoring stations, communications network, and data processing systems to enable real time rating calculations. Potentially requires Code changes by the Electricity Authority to enable market and tools to be compatible with real time ratings. Requires Market tools to be developed to be compatible with real time ratings. Market participants will need to be consulted as real time ratings is not something the market has had to deal with in the past. On the interconnected grid, capacity needs depend on the most economic dispatch of generation. Therefore, the periods where DLR provides better ratings may not coincide with periods where the market would benefit from the additional capacity.	NO Dynamic line rating would require code changes in the market. High flows on CNI can be driven by hydro/wind in the SI and lower NI. It is unlikely that a clear correlation between high ratings and high flows will exist
Transmission options - new assets or replacing existing assets					
D1	New Line	**New 220 kV line between Bunnythorpe and Whakamaru** [8 years property acquisition and consenting + 5 years build]	A new 220 kV double circuit duplex line between Bunnythorpe and Whakamaru	Following the existing Bunnythorpe-Whakamaru A&B routes, a new double circuit 220 kV duplex line could be constructed. As the new line would likely pass through nationally significant areas, which are volcanically active, the time for property acquisition and consenting poses a risk to this option. This is a long-term solution and would require a partial solution in the interim to achieve the required capacity in 5 years from now.	YES This is a long term option that will be further examined. Specific areas and routes will be analysed in phase 2 of NZGP
D2	New Line within the Taranaki transmission corridor	**New 220 kV line Bunnythorpe-Stratford-Huntly** [10 years property acquisition and consenting + 7 years build]	A new 220 kV double circuit duplex line between Bunnythorpe - Stratford - Huntly	This new line can be developed in stages: 1. Stage 1 – a new double circuit line between Huntly–Stratford 2. Stage 2 – a new double circuit line between Bunnythorpe–Stratford. This stage could be deferred by upgrading existing lines between Bunnythorpe–Stratford. The new Bunnythorpe–Stratford route would follow the existing Brunswick-Stratford A and Bunnythorpe-Brunswick A lines. A new route is probably required from Stratford to Huntly. Of all the new line options this covers the longest distance and presents the most difficult terrain to cover, particularly between Huntly and Stratford.	YES This new line option combines with option D1 for further analysis in NZGP phase 2

Option Type	Option sub-type	Option (duration of works)	Details	Comments	Considered further
D3	New Line within the Hawkes Bay transmission corridor	**New 220 kV line between Bunnythorpe-Woodville-Waipawa-Fernhill-Redclyffe-Wairakei** [10 years property acquisition and consenting + 5 years build]	A new 220 kV double circuit duplex line between Bunnythorpe - Woodville - Waipawa - Fernhill - Redclyffe- Wairakei	This option, if northern end terminates at Wairakei, will exacerbate the Wairakei Ring needs, and requires Wairakei Ring needs to be resolved first. Likely to require the line to be built from Wairakei towards Bunnythorpe end due to system needs. This increases the lead time before addition capacity is available for export of generation out of Bunnythorpe. The existing 110 kV Bunnythorpe-Woodville A and Fernhill-Woodville A lines would provide the route; however, the terrain would need some deviations. Only a partial solution, as the Wairakei-Whirinaki A line may still also need to be uprated.	YES This new line option combines with option D1 for further analysis in NZGP phase 2
D4	New Line within the existing Central North Island transmission corridor	**Replace the existing Bunnythorpe–Whakamaru-A and B lines to 400 kV** (10 years property acquisition and consenting + 5 years build)	Replace the existing 220 kV Bunnythorpe-Whakamaru A & B lines with 400 kV lines.	Requires 220/400 kV interconnection at either ends of the lines. Existing towers are not 400 kV capable therefore this option is equivalent to building new lines. However, costs and outage requirements for this option make it less feasible than building a new line (new lines are higher voltage class and existing lines have to be dismantled to re-use the route).	NO Under the present scenarios this level of capacity is not seen to be necessary
D5	New Line within the existing Central North Island transmission corridor	**Triplexing existing 220 kV Bunnythorpe-Whakamaru A and B lines** [8 years property acquisition and consenting + 5 years build]	Triplex the existing 220 kV simplex Bunnythorpe-Whakamaru A&B lines.	Existing towers are only designed for simplex loads, therefore triplexing requires significant tower and foundation strengthening, making this option similar to building a new line from a cost perspective. The outages to replace and strengthen these lines make this option less feasible than building a new line.	NO This option would require significant tower and foundation strengthening and would not be cost effective

D6	New Line within the Central North Island transmission corridor	**Upgrade Bunnythorpe-Ongarue A to 220 kV and terminate into Whakamaru** [8 years property acquisition and consenting + 5 years build]	Upgrade the existing 110 kV Bunnythorpe–Ongarue-A to 220 kV.	The existing Bunnythorpe–Ongarue A line is not 220 kV capable therefore this option is equivalent to building a new line. Requires alternate supply options for Mataroa, Ohakune, National Park and Ongarue substations that are currently supplied by the existing Bunnythorpe–Ongarue A line.	NO This is a high cost option that would be unlikely to pass the investment test
D7	New Line within the Central North Island transmission corridor	**Upgrade Bunnythorpe-Ongarue A to 220 kV and terminate into Taumarunui and upgrade capacity between Huntly-Taumarunui** (10 years property acquisition and consenting + 7 years build)	Upgrade the existing 110 kV Bunnythorpe-Ongarue A to 220 kV and terminate the circuit into Taumarunui. Upgrade the capacity of the existing Taumarunui to Huntly 220 kV line or build a new line in parallel.	The existing Bunnythorpe–Ongarue A line is not 220 kV capable therefore this option is equivalent to building a new line. Requires alternate supply options for Mataroa, Ohakune, National Park and Ongarue substations that are currently supplied by the existing Bunnythorpe–Ongarue A line. If a new line between 220 kV Taumarunui and Huntly is built, it may defer investments between Whakamaru and the Waikato and upper North Island region	NO This is a high cost option that would be unlikely to pass the investment test
D8	New Line within the Central North Island transmission corridors	**Build a new 220 kV cable between Bunnythorpe and Whakamaru** (10 years property acquisition and consenting + 7 years build)	Build a new 220 kV cable between Bunnythorpe and Whakamaru	This option is technically challenging as long cables have very high charging currents. Charging currents reduces available capacity to carry power and causes high voltages (exceeding designed limits) at the opened end. A common solution to tackle this issue is to install shunt reactors to compensate the charging currents. Multiple substations with shunt reactors will be required along the cable route which increases cost. This option will be of many magnitudes (in the order of 5-10x) more costly than building a new 220 kV overhead line.	NO This is a high cost option that would be unlikely to pass the investment test
D9	HVDC transmission option	**Extend the HVDC NI terminal to Whakamaru** (10 years property acquisition and consenting + 7 years build)	Build a new 350 kV HVDC line between Haywards and Whakamaru and install a new convertor station at Whakamaru	Although new HVDC lines are slightly cheaper to construct than 220 kV HVAC lines, the HVDC line length is significantly more as it needs to cover Haywards to Bunnythorpe section as well. This coupled with the cost of a convertor station will make this option significantly more expensive than a new 220 kV line option.	NO This option would be prohibitively expense and would not pass the investment test. Should MBIE announce the construction of a large Onslow, this could be revisited

D10	HVDC transmission option	**Extend the HVDC NI termination to Huntly** (10 years property acquisition and consenting + 10 years build)	Build a new 350 kV HVDC line between Haywards and Huntly and install a new convertor station at Huntly	Although new HVDC lines are slightly cheaper to construct than 220 kV HVAC lines, the HVDC line length is significantly more as it needs to cover Haywards to Bunnythorpe section as well. This coupled with the cost of a convertor station will make this option significantly more expensive than a new 220 kV line option. Transmission losses will be higher than a HVAC option due to the significant length (high resistance) and relative low voltage (high currents) Some 220 kV HVAC lines between Whakamaru and the Waikato and Upper North Island region may be repurposed for HVDC operation.	NO This option would be prohibitively expense and would not pass the investment test. Should MBIE announce the construction of a large Onslow, this could be revisited

Table 7: CNI Components that could potentially meet all or a part of the need. This list may contain “tactical” options, which meet the need in the short-term need, but are followed by another option to meet long-term need

Q4. Is our reduced list of options for enhancing capacity of the CNI 220 kV corridor reasonable?

3.4 Wairakei Ring Long List Options

Option Type	Option sub-type	Option (duration of works)	Details	Comments	Considered further
A1	Do Nothing (Counterfactual)		Assumes reactor at 19.5 ohms		YES
		Non-Transmission Options			
B1	Battery Storage	**Battery installed north of constraint** (duration to be confirmed**)**	A battery would need to act as a generator and/or only discharge on command, requiring a SPS system to work with the battery. If it only discharges on command: a SPS would detect a Tokaanu–Whakamaru circuit overload and ramp up the output of the battery while ramping down generation south of Whakamaru	This solution would have to be accepted by the industry participants and regulator, including the development of protection grade communications and other SPS associated investments. Such a battery would need to be large, but could potentially also provide reserves for the HVDC but not voltage support. HVDC could set the capacity (MW) needs of the battery and the minimum energy (MWh) needs while CNI adds in the energy needs that it could justify Such a battery could potentially also address other constraints south of Whakamaru such as on the CNI	YES Non-transmission options will be considered separately. These solutions have potential to enable outages.
B2	Generation Redispatch	**Automatic generation controller (AGC)** (duration to be confirmed**)**	AGC would detect overloading of Wairakei Ring circuits and automatically reduce generation in the Wairakei/Eastern Bay of Plenty/Hawkes Bay regions while increasing generation north of Whakamaru to remove the overload.	This would require agreement between affected asset owners and would be subject to compatibility of different assets to facilitate such a scheme. Such an arrangement may be more likely to be acceptable for a short term e.g., to defer transmission or assist with obtaining requisite outages.	YES Non-transmission options will be considered separately. These solutions have potential to enable outages.

B3	Load shedding	**Automatic scheme to concurrently reduce demand and generation to resolve grid overloads** (duration to be confirmed**)**	Automatic scheme to detect overloading of Wairakei Ring circuits and automatically and concurrently reduce demand north of Whakamaru and generation in the Wairakei/Eastern Bay of Plenty/Hawkes Bay regions to remove the overload.	This would require agreement between affected demand and generation customers to facilitate such an SPS. This is technically more challenging than installing AGC as there is no ability to precisely control demand like generation. Such an arrangement may be more likely to be acceptable for a short term e.g., to defer transmission or assist with obtaining requisite outages.	YES Non-transmission options will be considered separately. These solutions have potential to enable outages.
Transmission options - modifying and upgrading existing assets					
C1	Line upgrade	**Thermally upgrade Wairakei-Whakamaru A line, Wairakei-Whakamaru C line and Eastern Bay of Plenty 220 kV circuits (Edgecumbe-Kawerau-Ohakuri 220 kV)** (approximately 3 years to build + 2-years for consenting and planning)	High level of uncertainty on the cost and time required to thermally upgrade Wairakei-Whakamaru A line and Edgecumbe-Kawerau-Ohakuri 220 kV circuits (currently at 50°C). This option does not materially resolve Wairakei Ring constraints but is an option to relieve constraints on Eastern Bay of Plenty generation.	Thermal upgrade of Wairakei-Whakamaru C line is possible.	NO Grease migration temperature of the A line conductor means uprating the line temperature is not feasible
C2	Reconfiguration	**Reconfigure Atiamuri-Ohakuri reactor impedance and thermally upgrade the Wairakei-Whakamaru C line.** (3 years to build + 2 years for consenting and planning)	Thermal upgrade of Wairakei-Whakamaru C line is possible. This option is likely to only provide a modest increase in capacity on the Wairakei Ring.	Thermal upgrade of the WRK-WKM C line is limited to 100degC due to the annealing temperature of the conductor	YES Although the capacity increase from this option would be modest, the price is also small so the investment may be economic
C3	Reconfiguration	**Reconfigure the Wairakei 220 kV bus and split the network to potentially increase load sharing on the Wairakei 220 kV circuits** (duration to be confirmed**)**	Reconfigurations will involve investments which could be significant if the 220 kV bus must be rebuilt. Reconfigurations may also reduce transfer capacity on the CNI corridor.	There is no obvious reconfiguration option to further increase capacity through the Wairakei Ring.	NO There is no option to reconfigure that would provide additional capacity
C4	Bussing C line	**Bussing C Line** (duration to be confirmed**)**	Bussing can be beneficial in cases where some parallel lines are underutilised as it generally improves load sharing among them.	High level load flow analysis shows there to be no benefits as all three lines are already well utilised. Would require designation/NOR and regional consents. Need to avoid SNA. Time and cost to secure approvals. To consider archaeology and cultural impact.	NO There is no capacity increase gained through this option

C5	Line Compensation	**Active Line Compensation** (duration to be confirmed**)**	Install active line compensation devices to actively optimise impedance of Wairakei Ring circuits to maximise transfer capacity	Technically feasible but the Electricity Market currently operates with a static power system. Active Line compensation will require the Market and the Market tools to be adapted to work with a dynamic power system. This option is unlikely to be achievable in the 0-5-years' timeframe as code changes may be required in addition to tool upgrades etc (similar challenges to DLR).	NO This option would require the development of market tools in conjunction with the Electricity Authority and is outside the scope of this investigation
Transmission options - new assets					
D1	HVDC	**HVDC terminal** [5 years property acquisition and consenting + 7 years build]	Tap into HVDC that is on the way to Whakamaru. If the preferred option for CNI and HVDC is to extend the HVDC to Whakamaru, tap into HVDC at Wairakei if the HVDC traverses the site or deviate the HVDC to Wairakei if it doesn't.	This option will require it to align with HVDC and CNI projects as the proposal is to tap into new HVDC lines headed north towards Whakamaru. Tapping into HVDC, or building new HVDC, require converter stations that are in the order of ~$250m each. Suggest this makes these options infeasible.	NO The CNI preferred solution is not to build additional HVDC assets
D2	HVDC	**Back-to-back HVDC terminal** [2 years consenting and planning +5 years build]	Install back-to-back HVDC between Atiamuri-Ohakuri plus thermal upgrade Wairakei-Whakamaru C line.	This option will allow the power flow across the Wairakei Ring to be coordinated (using the back-to-back HVDC to steer power flow), allowing the maximum capacity of the Wairakei Ring to be used (i.e., 100% utilisation of all three circuits) Likely to be more costly than line upgrades (due to short lengths) while offering less capacity as it is still limited by the capacity of existing circuits.	NO This option is cost prohibitive when compared to HVAC construction options and would not pass the investment test
D3	HVDC	**HVDC Light system between Wairakei-Whakamaru** [3 years property acquisition and consenting + 5 years build]	Install HVDC light between Wairakei-Whakamaru by converting existing HVAC line to HVDC operation (maybe one of the Wairakei-Whakamaru C line circuits)	HVDC light is smaller scale HVDC systems that are often the result of conversions of HVAC assets into HVDC operation. The idea is that converting HVAC lines to HVDC will increase the power transfer limits between two or more points that are currently served by HVAC lines that are nearing or at capacity and obtaining another transmission corridor is much more expensive or impractical. HVDC is usually more cost effective for transmission over long distances, so it is unlikely to be the most cost-effective approach to address the Wairakei Ring constraints.	NO This option is cost prohibitive when compared to HVAC construction options and would not pass the investment test

Option Type	Option sub-type	Option (duration of works)	Details	Comments	Considered further
D4	New Line	**Connect into 400 kV lines between Bunnythorpe and Whakamaru** [3 years property acquisition and consenting + 10 years build]	Connect into 400 kV lines between Bunnythorpe and Whakamaru. If the preferred option for CNI and HVDC is to build a 400 kV line between Bunnythorpe and Whakamaru, bus the line at Wairakei if it traverses the site or deviate the line into Wairakei if it doesn't. A new 400 kV substation is required at Wairakei.	This is a long-term solution and would require a partial solution in the interim to achieve the required capacity in 5 years from now.	NO The CNI preferred solution is not to build additional HVDC assets
D5	New Line	**New line from Ohaaki (OKI) to Atiamuri and new Atiamuri-Whakamaru double circuit to replace current section of the A line** [3 years property acquisition and consenting + 7 years build]	New 220 kV line from Ohaaki to Atiamuri and upgrade existing Atiamuri-Whakamaru section of the Wairakei-Whakamaru A line to a 220 kV double circuit line	This option increase security of supply to the Bay of Plenty region It may be more economic to build a new line between Atiamuri-Whakamaru and then dismantle that section of the Wairakei-Whakamaru A line due to the length of outage required to upgrade it to a double circuit.	NO This option has been further refined since longlisting and is now shown as option D5A
D5A	New Line	**New line from Wairakei to Ohakuri and Duplex Ohakuri to Whakamaru** [2 years consenting and planning + 4 years build]	New 220 kV line from Wairakei to Ohakuri and upgrade existing Ohakuri-Whakamaru section of the Wairakei-Whakamaru A line to a 220 kV duplex line	This option may prove to be an economic balance of new and upgraded lines and would provide sufficient capacity.	YES This option would also include the C line TTU option and should be explored further
D6	New Line	**Third line in the Wairakei Ring transmission corridor** [2 years consenting, and planning + 4 years build]	New double circuit 220 kV line between Wairakei-Whakamaru in parallel to the existing lines	This option could increase security of supply/resilience to the Bay of Plenty region if it connects into Atiamuri. However, the preferred transmission corridor may not allow this to be the case. A double circuit line is preferred as it creates optionality for the future.	YES This option provides additional capacity and should be explored further
D7	New Line	**New 220 kV line** [2 years consenting and planning + 4 years build]	New double circuit line to replace the A line (duplex Sulfur at 75degC), second circuit bypassing Ohakuri	This option increase security of supply to the Bay of Plenty region It may be more economic to build a new line between Atiamuri-Whakamaru and then dismantle the Wairakei-Whakamaru A line due to the length of outage required to replace it.	YES This option provides additional capacity and should be explored further

D8	New Line	**New double cct line** [2 years consenting and planning + 4 years build]	New double circuit line Wairakei-Ohakuri-Atiamuri only, replaces existing section of the A line	This option was one of the future development paths for the Wairakei Ring analysis that justified the Wairakei-Whakamaru C line. However, this option is not suitable today as the Bay of Plenty region's demand is not large enough to consume much of the generation from Wairakei	NO This option does not increase the ability to export Wairakei generation to Whakamaru which is our current need
D9	Upgrade the Central Corridor	**Duplex reconductoring existing 220 kV lines** 2 years consenting and planning + 4 years build]	Duplex reconductoring Wairakei-Whakamaru A line (duplex Sulfur at 75degC)	Scope for duplexing may include significant structure replacements, increasing the cost of this option. Outages required to facilitate the duplexing work may also impact the economics of this option does not increase the security of supply to the Bay of Plenty region like new line options that terminate at Atiamuri	YES This option provides sufficient capacity for the need so should be explored further
D10	Upgrade the Central Corridor	**Simplex reconductoring existing 220 kV lines** [2 years consenting and planning + 4 years build]	Simplex reconductoring Wairakei-Whakamaru A line (simplex Chukar at 90degC) plus thermal upgrading the Wairakei-Whakamaru C Line	Scope for simplex reconductoring with a larger conductor may include significant structure replacements, increasing the cost of this option. Outages required to facilitate the reconductoring work may also impact the economics of this option does not increase the security of supply to the Bay of Plenty region like new line options that terminate at Atiamuri	NO This option would not provide the same capacity as duplex option D9
D11	New Line	**New 220 kV line plus reconductoring existing 220 kV lines** [2 years consenting and planning + 4 years build]	New single cct line between Wairakei-Atiamuri and reconductor (duplex) between Atiamuri-Whakamaru, keep existing A line	Increases security of supply/resilience to the Bay of Plenty region. Scope for reconductoring with a larger conductor may include significant structure replacements, increasing the cost of this option. Outages required to facilitate the reconductoring work may also impact the economics of this option	NO A single circuit line would not provide the same level of capacity or flexibility as a double circuit line
D12	New Line	**New 220 kV line** [2 years consenting, and planning + 4 years build]	New single cct line between Wairakei-Atiamuri-Whakamaru, keep existing A line (duplex Sulfur at 75degC)	This option is a variation of option D6. A new 220 kV line will not offer future flexibility that a new double circuit line does	NO This option is a variation of option D6. A new single circuit 220 kV line will not offer the future flexibility that a new double circuit line does

Table 8: AC Components that could potentially meet all or a part of the need. This list may contain "tactical" options, which meet the need in the short-term need, but are followed by another option to meet long-term need

Q5. Is our reduced list of options for enhancing capacity of the Wairakei Ring reasonable?

3.5 Shortlisting criteria

Our long list of options were evaluated using high-level screening criteria, including indicative cost. The screening criteria are used to eliminate those options that are not appropriate for consideration in the shortlist and subsequent development plans, to which we apply the Investment Test. The outcome of applying the shortlisting criteria is reflected in Tables 9 and 10. The criteria are described further here:

1. Fit for purpose
    - The design will meet current and forecast energy demand
    - The extent to which the option resolves the relevant issue

2. Technically feasible
    - Complexity of solution
    - Reliability, availability and maintainability of the solution
    - Future flexibility – fit with long term strategy for the grid
    - Ideally the design can be staged and/or has flexibility to preserve options for future changes

3. Practical to implement
    - It must be possible to implement the solution by the required dates
    - Implementation risks, including the likelihood of obtaining any necessary outages and potential delays due to property and environmental issues, are manageable

4. Good electricity industry practice (GEIP)
    - Ensures safety
    - Consistent with good international practice
    - Ensures environmental protection
    - Accounts for relative size, duty, age and technological status
    - Technology risks

5. Provides system security
    - Improves resilience of the power system
    - Has benefits for system operation (e.g., controllability)
    - Improves voltage stability (e.g., has modulation features or improves system stability)

6. Indicative cost
    - Whether an option will clearly be more expensive than another option with similar or greater benefits

3.6 Intermediate development plan options

The long-lists of options were developed differently in the three different staging project investigations. The HVDC and Wairakei Ring options were developed as combinations of individual component options from the beginning, but for the CNI, component options were developed.

The options evaluated in the Investment Test are combined options, referred to as development plan options. For CNI, these are combinations of more than one shortlisted option.

In general, the development plan options include combinations of options, commissioned at different times. For instance, where a component option has a long lead-time e.g., building a new transmission line, we may also include a short-term, or “tactical” option to enhance capacity until such time as a new line can be commissioned.

A summary of the development plan options is shown in Table 9. They are called intermediate development plan options. To apply the Investment Test to the options which upgrade the existing grid, we combine an HVDC development plan option with a CNI development plan option and a Wairakei Ring development plan option. The total number of options becomes intractable. The benefits for each option are identified using SDDP, a proprietary load-flow modelling tool. To undertake full Investment Test analysis for 2x HVDC, 11x CNI, 7x Wairakei ring options over 5 scenarios would require 770 SDDP runs, which is intractable.

Our Investment approach was to evaluate the options which upgrade the existing grid first and compare only the preferred option from that analysis with options 1 and 2 below.

We used a simplified analysis to reduce the intermediate list to a shortlist for Investment Test analysis.

List of intermediate development plan options									
Base Case									
Option 0	Do not enhance existing grid								
Options to meet the overall need and bypass the existing grid									
	New North Island HVDC	New inter-island HVDC							
Option B1	✓								
Option B2		✓							
Options to enhance HVDC capability									
	New HAY reactive support 1200MW	4th Cook Strait cable 1400MW							
Option H1	✓								
Option H2		✓							
Options to enhance CNI capacity									
	BPE-ONG split	HLY-SFD protect upgrade	BRK-SFD enhance	TTU TKU-WKM	TTU BPE-TKU	TTU BPE-WRK	Duplex TKU-WKM	Duplex BPE-TKU	New line north BPE
Option C1	✓	✓	✓	✓					
Option C2	✓	✓	✓	✓	✓				
Option C3	✓	✓	✓	✓		✓			
Option C4	✓	✓	✓	✓	✓	✓			
Option C5	✓	✓	✓	✓			✓		
Option C6	✓	✓	✓	✓	✓		✓		
Option C7	✓	✓	✓	✓	✓		✓	✓	
Option C8	✓	✓	✓	✓	✓	✓	✓	✓	
Option C9	✓	✓	✓	✓	✓				✓
Option C10	✓	✓	✓	✓	✓	✓			✓
Option C11	✓	✓	✓	✓	✓		✓	✓	✓
Options to enhance WRK capacity									
	EDG-KAW split	TTU WRK-WKM C line	Duplex WRK-WKM A line	TTU EDG-KAW	Replace WRK-WKM A Option D5A	Replace WRK-WKM A Option D7	New WRK-WKM D line	WRK sub equip	
Option W1	✓	✓							
Option W2	✓	✓	✓						
Option W3	✓	✓	✓	✓					
Option W4	✓	✓		✓	✓				
Option W5	✓			✓		✓		✓	
Option W6	✓	✓		✓		✓			
Option W7	✓			✓			✓	✓	

Table 9: list of Intermediate development plan options matrix

We undertook a simplified analysis to reduce the intermediate list to a shortlist for Investment Test analysis.

Our approach and results are described in Appendix A, with the outcome being the following shortlist of options which were evaluated in the Investment Test.

List of shortlisted development plan options									
Base Case									
Option 0	Do not enhance existing grid								
Options to meet the overall need and bypass the existing grid									
	New North Island HVDC	New inter-island HVDC							
Option B1	✓								
Option B2		✓							
Options to enhance HVDC capability									
	New HAY reactive support 1200MW	4th Cook Strait cable 1400MW							
Option H1	✓								
Option H2		✓							
Options to enhance CNI capacity									
	BPE-ONG split	HLY-SFD protect upgrade	BRK-SFD enhance	TTU TKU-WKM	TTU BPE-TKU	TTU BPE-WRK	Duplex TKU-WKM	Duplex BPE-TKU	New line north BPE
Option C6	✓	✓	✓	✓	✓		✓		
Option C8	✓	✓	✓	✓	✓	✓	✓	✓	
Option C9	✓	✓	✓	✓	✓				✓
Options to enhance WRK capacity									
	EDG-KAW split	TTU WRK-WKM C line	Duplex WRK-WKM A line	TTU EDG-KAW	Replace WRK-WKM A plan A	Replace WRK-WKM A plan B	New WRK-WKM D line	WRK sub equip	
Option W1	✓	✓							
Option W4	✓	✓		✓	✓				
Option W7	✓			✓			✓	✓	

Table 10: Short list development plan options matrix

This list still comprises 2 x HVDC, 3 x CNI and 3 x Wairakei Ring options, meaning 90 SDDP runs altogether to complete the Investment Test.

4.0 Options analysis

4.1 Investigation Approach

The diagram below sets out the general process followed by this investigation. We are at the 'Option Analysis' stage.

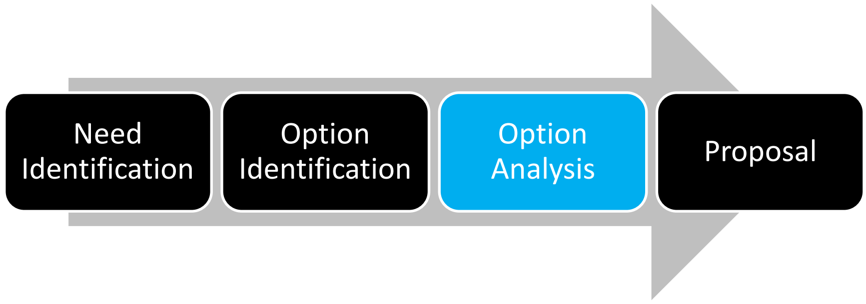

Figure 11: Transpower's standard investigation approach

Once we have received feedback to this consultation, we will finalise our development plan options, considering the availability of third parties to undertake the construction works while continuing to fulfil obligations to other Transpower work.

We will engage further with our Engineering Consultant partners to further refine the scope of work based on our development plans and will seek more refined pricing for our construction options.

We will then reassess the development plans using the Investment Test, as prescribed in Schedule D of the Capex Input Methodology[15]. In addition to quantifiable benefits, our assessment may also consider a range of unquantified benefits.

Sensitivity analysis will be undertaken to test the robustness of the Investment Test result and should or development plan options continue to pass the Investment Test, an MCP application will be prepared and submitted to the Commerce Commission.

4.11 Relationship of the new TPM with the investment test

As noted in section 2.1 above, allocations to recover the costs of this investment would be made under the new TPM.

As some of the component investments are 'high-value' benefit-based investments (BBI) (over the base capex threshold in the Transpower Capex IM, a capital cost of $20 million) the TPM's standard methods will be used to calculate customer allocations for those investments. The simple method may be used for components with a capital cost of less than $20m. Where we are using the standard method, the assumptions and other inputs (including the factual, counterfactual, modelled constraints and scenarios) Transpower uses in applying a standard method to a BBI must be *"as consistent as reasonably practicable with the assumptions and other inputs used in applying the*

[15] Transpower Capital Expenditure Input Methodology Determination 2012 (Principal Determination), 1 June 2018

Investment Test, except … to the extent Transpower determines such alignment would not produce BBI customer allocations that are broadly proportionate to positive NPB from the post-2019 BBI, in which case Transpower may use different assumptions and other inputs provided they do not contradict what Transpower determines were its key drivers…"[16].

4.12 The role of the TPM

The Commerce Commission determines how much revenue Transpower, as the owner and operator of the National Grid owner, can recover from its customers according to its regulation of Transpower under Part 4 of the Commerce Act. The TPM determines how that amount of allowable revenue is recovered from (or allocated to) each of Transpower's customers in each pricing year.

Once Transpower's capital expenditure proposal has been approved by the Commerce Commission, whether as major capex or base capex, that spend (and an allowable return on investment) may be recovered through the TPM.

The Commerce Commission has noted:

The new TPM guidelines and the new TPM Transpower develops under them will not affect the regulatory approval process for assessing the [Major Capex Proposal] under the Capex IM or the amount Transpower can recover in transmission charges for the investment.[17]

4.2 Demand and generation scenarios

In line with the requirements of the Capex IM, the demand and generation scenarios considered in our analysis are based on the Electricity Demand and Generation Scenarios (EDGS)[18] published by MBIE.

The EDGS are hypothetical future situations relating to forecast electricity demand and generation and are developed by MBIE, specifically for the purpose of investigating major capex proposals. The Investment Test does allow for demand and generation scenario variations to be used, where the variations are of the EDGS and have reasonable regard to the views of interested persons.

Using demand and generation scenarios helps to ensure economic analysis is robust to future uncertainty around both electricity demand growth and generation expansion. While some investigations do not warrant the use of scenarios, this investigation certainly does. A demand and generation scenario includes assumptions about:

- future electricity demand[19]
- existing, decommissioned and future new generation connected to the transmission network

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[16] https://www.ea.govt.nz/assets/dms-assets/30/Certified-Instrument-TPM-Transmission-Pricing-Methodology-2022.PDF clause 43(5)

[17] Commerce Commission Decision and reasons on Transpower's Bombay Otahuhu Regional MCP, 19 March 2021, paragraph 27.

[18] Electricity demand and generation scenarios (EDGS) | Ministry of Business, Innovation & Employment (mbie.govt.nz)

[19] Including assumptions regarding base demand, electric vehicle uptake, solar PV uptake, distributed energy storage, etc.

- capital and operating costs for existing and future new generation
- fuel availability for generation
- fuel and carbon costs for generation
- grid-connected energy storage

The latest EDGS were published in 2019 but reflecting the rapid pace of change in New Zealand's energy sector currently, there have been several relevant and important changes which are not reflected in the EDGS 2019. These include, but are not limited to:

- COVID-19 effect on electricity demand
- MBIE generation cost stack update, which describes potential new generation plant information
- Tiwai aluminium smelter announcement to close in 2024 (and subsequent effect on North Island thermal generators)
- Investor interest in grid-scale batteries
- Government investigation of the Onslow pumped hydro scheme i.e., the NZ battery project

We therefore considered it necessary to vary the EDGS 2019 for the purposes of this investigation. To ensure we reflected the views of interested persons, we used a consultative approach to review the EDGS.

A full description of our interactions with stakeholders in reviewing the EDGS 2019 can be found on our website at:

https://www.transpower.co.nz/NZGP

We initially used a panel of external (to Transpower) experts to review the EDGS, in November and December 2020. Recordings of the online meetings we held with them are available at the web link above. The conclusions from those meetings were then included in a written consultation paper, which was published on our website in December 2020. That consultation was open for 8 weeks, closing in February 2021.

Feedback confirmed that we had good information to produce reasonable EDGS variations in terms of demand scenarios, but not enough information regarding generation scenarios.

We concluded that demand and generation scenario variations should be determined separately.

Hence, we undertook further consultation, via a written consultation paper, regarding generation scenarios in May 2021[20]. This targeted potential generation investors but was open to all stakeholders. That consultation was open for 6 weeks and closed in June 2021. Feedback suggested there is too much uncertainty regarding future generation possibilities for grid-connected generation in New Zealand, to reflect in just five nationally determined scenarios, as per the published EDGS.

As well as uncertainty around future generation technologies and where it will be built, we identified several large uncertainties which are too significant to spread across the EDGS:

- Tiwai closure date and any Southland replacement demand
- The possibility of Taranaki development, including offshore wind being built

[20] Link to our consultation paper

- Peaking and dry year reserve options:
    - South Island (Lake Onslow) development
    - North Island (with gas peaking allowed)
    - North Island (100% renewables with a combination of generation overbuild, batteries, demand response and perhaps pumped hydro or hydrogen)

Next, we published our first formal NZGP1 document – the long-list consultation document - in August 2021. That consultation was open for 6 weeks and closed in October 2021. The submissions we received (excluding two that were provided on a confidential basis) are published on our website.

In that document, we described a possible approach to developing scenarios suitable for NZGP1. The approach reflected the considerable uncertainty regarding where new generation will be built and the largely binary uncertainties described above, but was complex and necessarily involved significant judgement.

Although it was a possible approach, we decided it would be both difficult to apply, potentially contentious, and may be difficult to demonstrate to the Commerce Commission that the resultant scenarios were reasonable variations of the EDGS.

Therefore, we changed our approach and the scenarios we have used for this NZGP1 investigation, are more obviously aligned with EDGS 2019. We have used the same five scenarios as in EDGS 2019, but with updated inputs. The differences between scenarios is very similar to the EDGS 2019. We are calling our scenarios NZGP1 scenarios to differentiate them and ensure readers understand they are variants of the EDGS 2019 and not the original scenarios. The five scenarios are:

1. Reference - Current trends continue
2. Growth - Accelerated economic growth
3. Global - International economic changes
4. Environmental - Sustainable transition
5. Disruptive - Improved technologies are developed

Not all of the uncertainty identified in reviewing the EDGS 2019 is reflected in our NZGP1 scenarios, so we have also developed some sensitivity scenarios to be considered as well. They are sensitivity scenarios and not a formal part of the Investment Test. We have undertaken sensitivity analysis as required by the Capex IM for the Investment Test, but for the sensitivity scenarios we will only report what grid flows are likely if those futures emerge. They will help understand whether there are futures where our proposal in the NZGP1 MCP (should we prepare such a MCP) would not be required.

We discuss the sensitivity scenarios further in section 4.7. The outcomes are not reported in this short-list consultation document, but will be included in the NZGP1 MCP (should we prepare such a MCP).

A full description of our NZGP1 scenarios was published in December 2021 and this can be found on our website[21]. That description is not repeated here but a summary of important points is contained in Appendix A.

[21] Link to document

4.3 Scenario weightings

The Investment Test requires that we determine the expected net electricity market benefit for each option considered. The expected net electricity market benefit for an option, is the weighted average of the net electricity market benefit under each demand and generation scenario.

Schedule D, Division 2 clause D2 (1) of the Capex IM requires that:

"…each relevant demand and generation scenario is accorded the explicit or implicit weighting assigned to it by the party who developed the scenario, unless Transpower considers that alternative weightings should apply and has consulted on these as part of its consultation on the short list of investment options."

The original scenarios were developed by MBIE, but they did not address the issue of how each scenario should be weighted in the context of the Capex IM.

Therefore, we are proposing weightings and this consultation is intended to meet the requirements of the Capex IM as outlined in Schedule D, Division 2 clause D2 (1).

Our starting point is that unless weightings are otherwise specified, each scenario should be equally weighted. In the case of our five NZGP1 scenarios that implies each scenario is weighted 20%.

However, we note that the electricity demand growth in our scenarios is low compared to other industry forecasts – see figure 16. The Global scenario only has electricity demand growing from 40 TWh per annum now to 44 TWh by 2050. The Reference scenario only has electricity demand growing to 51 TWh by 2050. Both of these seem low if electrification is to play a role in New Zealand achieving net zero carbon by 2050. Our electric land transport uptake is forecast to average 15.9 TWh by 2050 and process heat electrification 6.8 TWh by 2050[22], for instance.

For that reason, we believe it is reasonable to accord a lower weighting to both the Global and Reference scenarios.

The maximum we consider reasonable for the Global scenario is 5% and would recommend zero weighting.

The maximum we consider reasonable for the Reference scenario is 10% and similarly recommend zero weighting.

The Growth, Environmental and Disruptive scenarios are more difficult to distinguish. Although they are different futures, we have no basis for preferring any one of them. For that reason, we recommend allocating the same, or very similar weightings to each of these scenarios.

[22] https://www.transpower.co.nz/resources/whakamana-i-te-mauri-hiko-empowering-our-energy-future

We have developed a set of four different weightings which cover the range of possibilities discussed above. These are shown in Table 11.

				Scenario		
		Global	Reference	Growth	Environmental	Disruptive
Weighting set						
1		20%	20%	20%	20%	20%
2		5%	10%	25%	30%	30%
3		0	10%	30%	30%	30%
4	preferred	0	0	33.3%	33.3%	33.3%

Table 11: Potential scenario weightings

In our Investment Test application described later, we determine expected net market benefit using all four weighting sets. This serves to meet the requirement for sensitivity analysis in regard to scenario weightings as described in Schedule D, Division 2 clause D7 (1)(h) of the Capex IM.

Q6. Are our scenario weighting sets reasonable?

4.4 The Investment Test Parameters

4.41 Calculation period

The Capex IM states the default calculation period for costs and benefits is 20 years but allows for it to be altered if benefits can be better captured using a different period. Some transmission assets have lives greater than 20 years, so relative benefits will continue to accrue for some options after the 20 year calculation period has ended. The effect of discounting future benefits to present values does diminish this effect, but nevertheless it can be significant. We have used a calculation period to 2050 to both reflect the net zero by 2050 carbon target and better capture the costs and benefits over their useful life. Although this is not the full economic life of some options, we consider this to be an appropriate trade-off between assessing benefits over the full economic life and assessing uncertain future benefits. We have not included a terminal benefit in 2050 for any option.

4.42 Value of expected unserved energy

The Value of Lost Load (VoLL), which is also known as Value of Expected Unserved Energy, is the assumed value to consumers of losing electricity supply as the result of an unplanned outage. We use this value to assess reliability benefits, in situations where different options deliver differing levels of reliability of supply. The Code specifies that VoLL should be $20,000/MWh. This value was determined in December 2004 and including inflation, equates to approximately $29500/MWh in $2022. We determined this value for our Investment Test analysis, but it has not been used. It may be relevant when we continue our investigations into a new CNI line, as discussed later in this document.

4.43 Discount rate

The Capex IM defines a standard real, pre-tax discount rate of 7%, with low and high sensitivities of 4% and 10% respectively. The discount rate of 7% was set at a time when that rate was close to Transpower's WACC and it seems high today. We note that the sensitivity values of 4% and 10% cover the range of alternatives that some parties argue should be used (4% is close to a Social Rate of Time Preference discount rate and 10% is close to a commercial discount rate), so we are satisfied that, provided the sensitivities are considered, the range of discount rate arguments is addressed.

4.44 Electricity market costs and benefits

Electricity market costs and benefits are those received or incurred by consumers of the electricity market during the calculation period, and which will affect net electricity market benefits. These include, but are not necessarily limited to:

- Fuel costs e.g., the cost of generating electricity
- Cost of involuntary demand curtailment e.g., the cost of lost load
- Cost of demand-side management
- Capital costs of modelled projects e.g., future assets that are likely to exist whose nature and timing is affected by an investment option, for instance new generation
- Relevant operation and maintenance costs e.g., costs of existing assets, options and modelled projects
- Cost of ancillary services
- Cost of losses, including transmission and local losses
- Third party contributions to the cost of a project
- Subsidies or other benefits provided under or arising pursuant to all electricity-related legislation and electricity-related administrative determinations
- Competition effects

4.45 Project costs

Project costs are costs reasonably incurred by Transpower prior to or during the calculation period in undertaking a major capex project. These include, but are not necessarily limited to:

- Capital expenditure, including capital expenditure for land purchased for an option
- Costs payable to a third party for testing
- Costs payable for commissioning of assets
- Operating, maintenance, and dismantling costs
- Compliance costs relating to applicable legislation and administrative requirements

Since the long-list consultation, all project streams excluding new line options on the central North Island, HVDC and Wairakei ring mentioned in this document have been costed via the engagement of concept design and/or solution study reports as appropriate. New line options have been costed using our internal knowledge of past projects, and we feel that this will be an acceptable level of accuracy for the preliminary Investment Test, noting that any final application for construction costs of new lines would form part of a stage 2 MCP application.

To this end, it should be noted that price of new line construction sits across a continuum of potential final cost when considering the variability we would face depending on line length and route, property types impacted and line configuration (both in terms of conductor configuration and the potential for different tower and/or pole setups). Any application as part of this stage 1 MCP, for new lines, would be for funding to further investigate options and potentially start on a process to define corridors and potential routes to allow construction costings to be more accurately defined, in order that such costs allow greater accuracy in subsequent Investment Test analyses.

For the HVDC cable upgrade, a Request for Pricing (RFP) process was undertaken with international vendors, seeking pricing for the manufacture, transport, and installation of appropriate undersea cables. We had a good response to this process and are comfortable with the price accuracy we have ended up with. We are also considering how timings can be co-ordinated with the end of life replacement of our current HVDC cables. A large portion of the cable pricing is for manufacturing setup and ship mobilisation to New Zealand. It is highly possible that any final investment decision into the installation of additional HVDC cable capacity would be made in parallel with an investment decision to replace the three current cables in order to achieve the economies of scale available and reduce the costs faced if we were to proceed with the two projects independently. As further analysis into the economics of bringing forward the replacement of the current cables has not yet been completed (nominal expected end of life is currently circa 2032), we have analysed the HVDC 1400MW option as carrying the full mobilisation costs. The cost of this project segment may reduce prior to submission of the MCP later this year.

General advice from respondents indicated that the lead time from placement of order until commissioning was four to five years, due in part to New Zealand's isolated location and the demand for undersea cables from large northern hemisphere projects. Due to the commercial sensitivity of such costs, we will not be providing detail of the estimated HVDC upgrade cost. The exception is that we will provide such details to the Commission under commercial confidence, if and when we do submit a MCP later this year.

Given this long lead time, we further tested with suppliers the viability of booking manufacturing capacity to await a trigger point (such as the confirmed closure of NZAS Tiwai point) in an effort to establish a reduced lead time to installation. This process was unsuccessful with little engagement from the RFS respondents.

In some options, where existing transmission lines would be upgraded, the outages required to implement parts of the option would have a market cost. Where the outages are significant, we have determined an approximate bypass line cost. A bypass line is a temporary transmission line, erected to avoid outages. We recently used a bypass line when undertaking maintenance on the HVDC line from the North Island cable termination station, to Haywards. Building such lines is expensive and time-consuming. In our Investment Test analysis we have used one-half that value as the estimated cost of the outage/s required. We suspect that rather than build a bypass line we would enter into a contract or contracts with market participants to enable the outage at a lower cost than building a bypass line. We will explore this further in our NTS evaluation and before we submit a MCP to the Commission. As for the HVDC upgrade costs, due to the commercial sensitivity required for a NTS evaluation, we will not be providing further details. The exception is that we will provide such details to the Commission under commercial confidence, if and when we do submit a MCP later this year.

4.46 Expected net electricity market benefit

We have determined the net electricity market benefit for each shortlisted option, for each demand and generation scenario, being its aggregated quantum of each electricity market benefit or cost element less its aggregated quantum of each project cost.

The expected net electricity market benefit, for each option is the weighted average of the net electricity market benefit under each demand and generation scenario, where the weighting is that determined for each demand and generation scenario, as discussed in section 4.31.

4.47 Passing the Investment Test

An investment option satisfies the Investment Test if:

- it has the highest expected net electricity market benefit compared to other investment options;
- it has a positive expected net electricity market benefit, unless it is designed to meet an investment need the satisfaction of which is necessary to meet the deterministic limb of the grid reliability standard, and
- it is sufficiently robust under sensitivity analysis.

The Capex Input Methodology recognises the inherent uncertainty in estimating costs and benefits in Investment Test analysis, and where the difference in expected net benefit between two investment options is within 10% of the project cost of the option which passes the Investment Test, the options are considered “similar”. All “similar” options pass the Investment Test and the Capex IM then allows unquantified benefits to be used to identify a preferred option.

Some electricity market benefits are unquantified. This occurs when the cost of calculating its quantum is likely to be disproportionately large relative to the quantum, or when its expected value cannot be calculated with an appropriate level of certainty due to the extent of uncertainties in underlying assumptions or calculation approaches. Competition effects may fall into this category, because subjective assessments of market behaviour are required to determine their magnitude. Similarly, resilience benefits fall into this category. Currently we do not have a suitable methodology for determining these to an appropriate level of certainty, yet they may be large, especially where an option includes building a new, geographically diverse line. For that reason, we have included funding in our Stage 1 MCP to further develop a suitable methodology.

4.48 Sensitivity analysis

Sensitivity analysis means consideration, except where not reasonably practicable nor reasonably necessary, of the effect on quantum of variations in the following parameters:

- forecast demand
- size, timing, location, fuel costs and operating and maintenance costs, relevant to existing assets, committed projects, modelled projects and the investment option in question
- capital cost of the investment option in question (including variations up to proposed major capex allowance) and modelled projects
- timing of decommissioning, removing or de-rating decommissioned assets
- the value of expected unserved energy
- discount rate
- range of hydrological inflow sequences
- relevant demand and generation scenario probability weightings
- in relation to any competition effects associated with an investment option, generator offering and demand-side bidding strategies
- any other variables that Transpower considers to be relatively uncertain.

4.5 Our preliminary application of the Investment Test

Our preliminary application of the Investment Test has been undertaken in two stages to make the necessary analysis tractable.

We reduced the long-list of options for each of the staged projects, but still had an intractable number of option combinations:

- Two HVDC options
- Thirteen CNI options
- Eight Wairakei Ring options

If we considered each combination for all five scenarios, that would result in 770 SDDP runs plus a Base Case for each scenario, which is unmanageable.

In order to reduce the number of SDDP runs required, we called this our intermediate list and have applied the Investment Test separately to combined HVDC and CNI options and the Wairakei Ring options. This intermediate Investment Test analysis approach was possible because we had observed that although linked, the ranking of the Wairakei Ring options was constant under different HVDC/CNI option combinations. Using this approach, we were able to reduce the options to a short list of:

- Two HVDC options
- Three CNI options
- Three Wairakei Ring options

This still resulted in 90 SDDP runs plus a Base Case for each scenario.

Diagrammatically, this process is summarised as:

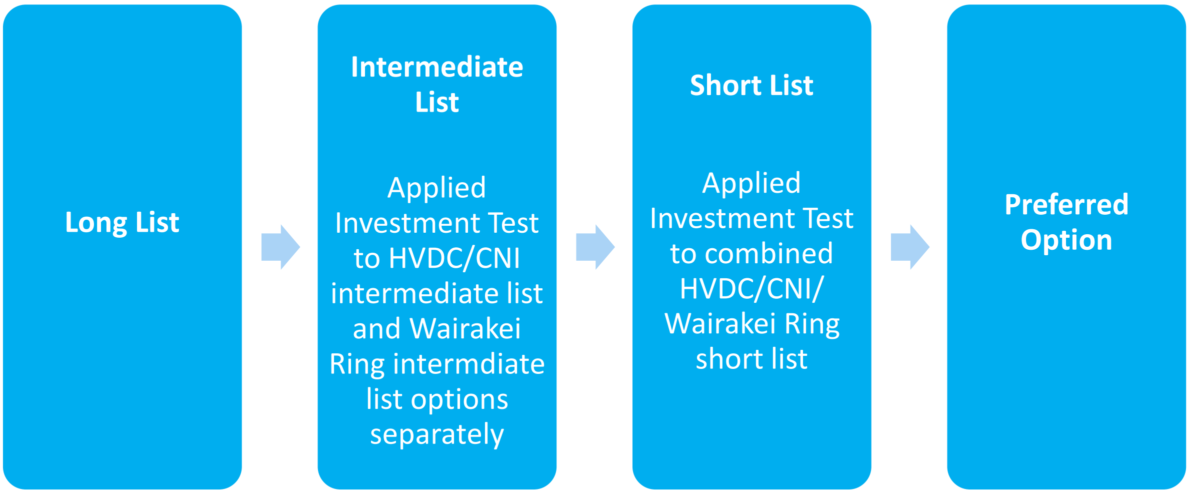

Figure 12: Long list to Preferred option process

4.51 Determining net electricity market benefit

The Investment Test requires that we determine the net benefit for each option studied. In this case the net benefit is:

Net electricity market benefit = Electricity market benefits – Electricity market costs

We have compared the before (investing in the transmission option) cost of meeting electricity demand, with the after cost of meeting electricity demand, for each option and each scenario to 2050.

Formulaically, this could be represented as:

Before cost = $(A + B)_{existgen} + (A + B)_{existgridnm} + (A + B)_{existgridmb} + C_{existgen} + D_{before}$

After cost = $(A + B)_{existgen} + (A + B)_{newgen} + (A + B)_{existgridnm} + (A + B)_{existgridma} + (A + B)_{newgrid} + C_{existnewgen} + D_{after}$

and the net benefit = $(A + B)_{existgen} + (A + B)_{newgen} + (A + B)_{existgridnm} + (A + B)_{existgridma} + (A + B)_{newgrid} + C_{existnewgen} + D_{after} - (A + B)_{existgen} - (A + B)_{existgridnm} - (A + B)_{existgridmb} - C_{existgen} - D_{before}$

$= (A + B)_{newgen} + (A + B)_{existgridma} - (A + B)_{existgridmb} + (A + B)_{newgrid} + C_{existnewgen} - C_{existgen} + D_{after} - D_{before}$

Where:

A = Respective capital costs

B= Respective operating and maintenance cost

C = Dispatch costs

D = Unserved energy costs

existgen = existing generation

existgridnm = existing grid not modified

existgridmb = existing grid modified, before modification costs

existgridma = existing grid modified, after modification costs

newgen = new generation

newgrid = new grid

existnewgen = Existing and new generation

before = before modification

after = after modification

4.52 Evaluating the intermediate list of HVDC and CNI options

To evaluate the full intermediate list of combined HVDC and CNI options would have been too many combinations. We sampled the list of combinations – not for the purposes of determining a preferred option, but in order to reduce the intermediate set of options to a short list. Our intermediate list analysis for the HVDC and CNI is shown in Tables 12 and 13, and our reasoning for the subsequent shortlist follows these results.

Net benefit of intermediate list of HVDC and CNI options										
	Scenario									
PV costs, $m	Global		Reference		Growth		Environmental		Disruptive	
HVDC option	H1 1200 MW	H2 1400 MW	H1 1200 MW	H2 1400 MW	H1 1200 MW	H2 1400 MW	H1 1200 MW	H2 1400 MW	H1 1200 MW	H2 1400 MW
CNI option										
C1	$317	$412	$317	$412	$317	$412	$317	$412	$317	$412
C2	$362	$457	$362	$457	$362	$457	$362	$457	$362	$457
C3	$345		$345		$345		$345		$345	
C4	$387	$482	$387	$482	$387	$482	$387	$482	$387	$482
C5	$358	$454	$358	$454	$358	$454	$358	$454	$358	$454
C6		$495		$495		$495		$495		$495
C7		$610		$610		$610		$610		$610
C8	$498	$594	$498	$594	$498	$594	$498	$594	$498	$594
C9		$807		$807		$807		$807		$807
C10	$735	$831	$735	$831	$735	$831	$735	$831	$735	$831
C11		$884		$884		$884		$884		$884
	Scenario									
PV benefits, $m	Global		Reference		Growth		Environmental		Disruptive	
HVDC option	H1 1200 MW	H2 1400 MW	H1 1200 MW	H2 1400 MW	H1 1200 MW	H2 1400 MW	H1 1200 MW	H2 1400 MW	H1 1200 MW	H2 1400 MW
CNI option										
C1	$307	$448	$207	$326	$583	$692	$359	$496	$65	$560
C2	$308	$450	$208	$327	$583	$694	$359	$496	$71	$562
C3	$307		$205		$582		$357		$63	
C4	$308	$454	$206	$327	$588	$687	$360	$497	$66	$558
C5	$316	$455	$224	$342	$602	$712	$384	$523	$117	$596
C6		$470		$352		$717		$532		$596
C7	$498	$501		$395		$761		$586		$650
C8	$357	$502	$271	$399	$656	$763	$443	$588	$163	$647
C9		$542		$456		$819		$658		$710
C10	$381	$527	$302	$434	$690	$795	$480	$630	$185	$676
C11		$542		$456		$819		$658		$710

	Scenario									
PV net benefit, $m	Global		Reference		Growth		Environmental		Disruptive	
HVDC option	H1 1200 MW	H2 1400 MW	H1 1200 MW	H2 1400 MW	H1 1200 MW	H2 1400 MW	H1 1200 MW	H2 1400 MW	H1 1200 MW	H2 1400 MW
CNI option										
C1	-$10	$36	-$110	-$86	$266	$280	$42	$84	-$251	$147
C2	-$54	-$7	-$153	-$130	$222	$237	-$2	$39	-$291	$105
C3	-$38		-$140		$237		$12		-$282	
C4	-$78	-$28	-$180	-$155	$202	$205	-$27	$15	-$321	$76
C5	-$43	$1	-$134	-$111	$244	$259	$25	$69	-$241	$142
C6		-$25		-$143		$222		$37		$101
C7	-$17	-$110		-$215		$151		-$24		$40
C8	-$141	-$92	-$227	-$195	$158	$169	-$55	-$6	$-335	$54
C9		-$265		-$352		$12		-$149		-$97
C10	-$355	-$304	-$434	-$397	-$46	-$36	-$256	-$201	-$550	-$155
C11		-$342		-$429		-$65		-$226		-$174

Table 12: Net benefit of intermediate list of CNI options

Table 13 shows various combinations of scenario weightings, ranging from the default 20% each weighting, to a weighting where the Global and Reference scenarios are weighted at zero, with the Growth, Environmental and Disruptive scenarios weighted at 33% each.

Net benefit of intermediate list of HVDC and CNI options with various scenario weightings, $PV net benefit, $m								
Scenario weighting	Weighting set 1 20/20/20/20/20		Weighting set 2 5/10/25/30/30		Weighting set 3 0/10/30/30/30		Preferred weighting set 4 0/0/33/33/33	
HVDC option	H1 1200 MW	H2 1400 MW	H1 1200 MW	H2 1400 MW	H1 1200 MW	H2 1400 MW	H1 1200 MW	H2 1400 MW
CNI option								
C1	-$13	$92	-$8	$133	$6	$145	$19	$170
C2	-$56	$49	-$51	$89	-$37	$101	-$24	$127
C3	-$42		-$38		-$24		-$11	
C4	-$81	$23	-$76	$62	-$62	$73	-$49	$99
C5	-$30	$72	-$19	$117	-$5	$130	$9	$157
C6		$39		$82		$94		$120
C7		-$31		$16		$29		$56
C8	-$120	-$14	-$107	$32	-$93	$46	-$77	$72
C9		-$170		-$119		-$105		-$78
C10	-$328	-$218	-$314	-$170	-$299	-$157	-$284	-$130
C11		-$247		-$196		-$182		-$155

Table 13: Net benefit of intermediate list of HVDC and CNI options with various scenario weightings

In Table 13, cells with negative net benefits are shaded in pink. The option with the highest net benefit is shown in the darkest green. The next lightest shade of green indicates net benefits which are “similar” under the Capex IM[23] and the other green cells indicate net benefits which are also “similar”, if the 10% parameter is raised to 13%.

As shown:

- The only options with a positive net benefit occur when the HVDC capacity is upgraded to 1400 MW
- Of those options, CNI option C1 has the highest net benefit
- CNI option C5 has a “similar” net benefit and if the 10% parameter is raised to 15%, CNI options C2 and C6 can also be considered “similar”.

Despite the HVDC only having positive net benefits when upgraded to 1400 MW, we are not recommending reducing the short list of HVDC options to one, but rather will carry both the 1200 MW and 1400 MW options forward.

With regard to the CNI options, in our view, CNI option C1 would not enable a wide range of futures. The benefits do not include a large amount of unserved energy, so in those futures it has been possible to find a generation expansion plan which works - but it is restricted. The fact that a generation expansion plan works for this option, reflects the abundance of wind and solar generation that New Zealand has access too. The MBIE generation stack includes some 10 GW of potential wind projects alone and the fact that CNI option C1 is feasible, is a result of that abundance.

If we compare the benefits for CNI options C1 and C11 (CNI option C11 would have the highest transmission capacity, we find that the benefits for CNI option C11 are $100 - $150 million, on a present value basis, higher than for CNI option C1. Only a small fraction of that benefit difference arises from a difference in capital costs (the projects on the MBIE generation stack reflect a similar cost), whereas a large fraction arises from North Island AC loss cost differences. Our modelling tells us that enough generation can be built in both options, but the generation built under CNI option C1 incurs higher losses.

We consider the long term interest of consumers is best served by not limiting the possibilities for generation investors and ensuring those investors can build their generation where they would prefer. In our view, the increase in competition benefits as a result of increasing accessibility to new generation, is an unquantified benefit which could be used to differentiate “similar” options.

Schedule D clause D1 3 allows the Commission to vary the 10% parameter and we will be recommending to the Commission in our MCP that this parameter be varied to 15% for the purposes of evaluating our application of the Investment Test. In our view, the uncertainties arising in which new generation projects are built are large and criteria used by generation developers in deciding whether their project should proceed or not are not all reflected just in a capital cost comparison. However, the competition benefit from enabling a more competitive generation

[23] The Capex IM recognises the inherent uncertainty in inputs to the cost-benefit analysis required by the Investment Test. Where the difference in net benefit between the option with the highest net benefit and another option is 10% or less of the aggregate project cost of the option with the highest net benefit, the options are considered “similar” and unquantified costs and benefits may be taken into account in order to identify a preferred option.

investment market is large. This translates back into a high level of uncertainty in the new generation costs on the generation and so the use of a higher than 10% parameter is warranted.

On the basis that is accepted, then CNI options C1, C2, C5 and C6 are all similar and since CNI option C6 enables the most competitive generation investment market, it would be akin to our preferred CNI option.

We also note that CNI option C8, which is the option which squeezes the most capacity out of our existing assets, has a positive net benefit under all weightings excepting the 20/20/20/20/20 weightings.

CNI options C9, C10 and C11 all involve building a new line north from Bunnythorpe. That would add considerable new capacity and depending upon the new line itself, would maximise the extent to which new generation is enabled, but building a new line will take time.

CNI option C8 provides more transmission capacity on the CNI lines than CNI option C6 and can implemented faster than CNI option C9.

We have arrived at our choice of shortlist options by considering the enabling ability of each option, leading us to CNI options C6, C8 and C9 (being the cheapest of our new line options). In our view this is an appropriate mix of shortlisted CNI options:

- Our nominally preferred option which would pass the Investment Test (if CNI was evaluated on its own and providing our recommendation to vary the 10% parameter is accepted);
- An option which squeezes the most out of our existing assets and which can implemented relatively quickly;
- An option which provides the highest CNI capacity.

Even our preferred option could be limiting depending on which future unfolds. For that reason, we consider it prudent not to drop the option which squeezes as much capacity out of the existing grid as possible (Option 12) and the option which involves building a new line. We note that all of these options provide a positive net benefit and would be economic in different circumstances. They are just not as economic as Option C1, which is the cheapest option.

Hence our shortlist of HVDC and CNI options, for Investment Test analysis is:

Short list of options for HVDC and CNI	
HVDC option H1	1200 MW
HVDC option H2	1400 MW
CNI option C6	TTU and duplex TKU-WKM A&B lines, TTU BPE-TKU A&B lines
CNI option C8	TTU and duplex BPE-WKM A&B lines, TTU BPE-WRK A line
CNI option C9	TTU BPE-WKM A&B lines, build a new line north from BPE

Table 14: Short list of options for HVDC and CNI

Q7. Is our shortlist of HVDC and CNI Options reasonable?

4.53 Evaluating the Intermediate list of Wairakei Ring options

As with the intermediate list of options for the CNI, we have an intermediate list of Wairakei Ring options which results in too many combinations for Investment Test analysis. As previously stated, we sampled the list of HVDC and CNI and Wairakei Ring combinations and found that although benefits for combinations of HVDC, CNI and Wairakei Ring options do vary with Wairakei ring options, the ranking of Wairakei Ring options does not vary as HVDC and CNI combinations are changed. This means we can reasonably evaluate the Wairakei ring options on their own – not for the purposes of determining the overall benefits, but in order to reduce the intermediate set of options to a shortlist. Our intermediate list analysis for the Wairakei Ring is shown in Tables 15 and 16, and our reasoning for the subsequent shortlist follows these results.

Net benefit of intermediate list of Wairakei Ring options					
PV costs, $m					
Scenario	Global	Reference	Growth	Environmental	Disruptive
Wairakei Ring option					
W1	$23	$23	$23	$23	$23
W2	$73	$73	$73	$73	$73
W3	$77	$77	$77	$77	$77
W4	$87	$87	$87	$87	$87
W5	$107	$107	$107	$107	$107
W6	$113	$113	$113	$113	$113
W7	$83	$83	$83	$83	$83
PV benefits, $m					
Scenario	Global	Reference	Growth	Environmental	Disruptive
Wairakei Ring option					
W1	$7	$10	$13	$13	$39
W2	$15	$22	$28	$29	$69
W3	$14	$22	$29	$31	$82
W4	$19	$32	$41	$45	$111
W5	$22	$37	$47	$51	$135
W6	$22	$37	$48	$51	$135
W7	$25	$41	$53	$58	$147
PV net benefits, $m					
Scenario	Global	Reference	Growth	Environmental	Disruptive
Wairakei Ring option					
W1	-$2	$0	$3	$3	$29
W2	-$46	-$38	-$32	-$31	$9
W3	-$49	-$41	-$35	-$32	$18
W4	-$55	-$42	-$33	-$29	$37
W5	-$72	-$58	-$47	-$43	$41
W6	-$78	-$64	-$52	-$49	$35
W7	-$44	-$29	-$16	-$12	$78

Table 15: Net benefit of intermediate list of Wairakei Ring options

Table 16 shows various combinations of scenario weightings, ranging from the default 20% each weighting, to a weighting where the Global and Reference scenarios are weighted at zero, with the Growth, Environmental and Disruptive scenarios weighted at 33% each.

Net benefit of intermediate list Wairakei Ring options, various scenario weightings, $PV net benefit, $m				
Scenario weighting	Weighting set 1 20/20/20/20/20	Weighting set 2 5/10/25/30/30	Weighting set 3 0/10/30/30/30	Preferred Weighting set 4 0/0/33/33/33
Wairakei Ring option				
W1	$7	$10	$10	$12
W2	-$28	-$21	-$10	-$18
W3	-$28	-$20	-$8	-$16
W4	-$24	-$13	-$1	-$8
W5	-$36	-$22	-$5	-$16
W6	-$42	-$28	-$9	-$22
W7	-$5	$11	$18	$17

Table 16: Net benefit of intermediate list of Wairakei Ring options with various scenario weightings

In Table 16, cells with negative net benefits are shaded in pink. The option with the highest net benefit in each scenario is shown in the darkest green. The next lightest shade of green indicates net benefits which are "similar" under the Capex IM[24].

Option W7 would pass the Investment Test with all other weightings than the default weightings and the net benefit is positive.

Option W1 would pass the Investment Test with the default scenario weightings and the net benefit is positive.

Option W7 passes the Investment Test with all other weightings and the net benefit is positive.

Option W1 is "similar" using the default 10% parameter, for all weightings other than the default weightings.

Option W1 is to TTU the existing WRK-WKM C line only, while Option W7 reflects building a new WRK-WKM D line.

Option W1 and W7 are taken forward to the shortlist, but we would also like to take forward option W4, which involves replacing the existing WRK-WKM A line. Options W4, W5 and W6 all involve replacing the existing WRK-WKM A line and although we are taking forward the cheapest option to the shortlist, we will consider options W5 and W6 further should option W4 appear to be economic.

We are less sure about the costs of our new line options at this stage and so cannot be sure, if one of these options is most economic, which might be best.

We note that our shortlist of options mirrors the mix of shortlist options for the CNI lines: We have arrived at our choice of shortlist options by considering the enabling ability of each option, leading

[24] The Capex IM recognises the inherent uncertainty in inputs to the cost-benefit analysis required by the Investment Test. Where the difference in net benefit between the option with the highest net benefit and another option is 10% or less of the aggregate project cost of the option with the highest net benefit, the options are considered "similar" and unquantified costs and benefits may be taken into account in order to identify a preferred option.

us to options W1, W4 and W7. In our view this is an appropriate mix of shortlisted Wairakei Ring options:

- We have an option which could be implemented relatively quickly – option W1 is a TTU of an existing line only
- An option which squeezes the most out of our existing assets, option W4, which would involve uprating the capacity of the existing WRK-WKM A line
- An option which provides the highest Wairakei Ring capacity, building a new line

In summary our shortlist of Wairakei Ring options, for Investment Test analysis is:

Short list of options for Wairakei Ring	
Wairakei Ring option W1	TTU WRK-WKM C line
Wairakei Ring option W4	TTU WRK-WKM C line and replace WRK-WKM A Option D5A
Wairakei Ring option W7	Construct a new WRK-WKM D line

Table 17: Short list of options for Wairakei Ring

Q8. Is our shortlist of Wairakei Ring options reasonable?

4.54 Investment Test analysis of the shortlisted options

For the purposes of applying the Investment Test, we have defined shortlist options for each of the HVDC, CNI and Wairakei Ring combinations.

A summary of our shortlisted options is:

Shortlisted option	HVDC option	CNI option	Wairakei Ring option
Option 1	H1	C1	W1
Option 2	H1	C1	W4
Option 3	H1	C1	W7
Option 4	H1	C8	W1
Option 5	H1	C8	W4
Option 6	H1	C8	W7
Option 7	H1	C11	W1
Option 8	H1	C11	W4
Option 9	H1	C11	W7
Option 10	H2	C1	W1
Option 11	H2	C1	W4
Option 12	H2	C1	W7
Option 13	H2	C8	W1
Option 14	H2	C8	W4
Option 15	H2	C8	W7
Option 16	H2	C11	W1
Option 17	H2	C11	W4
Option 18	H2	C11	W7

Table 18: summary of our shortlisted options

We have determined the costs of these options and undertaken SDDP analysis to determine the benefits.

Option cost and benefits PV $m						
		Scenario				
Shortlisted option	Option cost PV $m	Global	Reference	Growth	Environmental	Disruptive
Option 1	$413	$187	$180	$603	$192	$271
Option 2	$486	$200	$203	$633	$227	$346
Option 3	$482	$205	$213	$645	$242	$391
Option 4	$512	$227	$224	$650	$249	$319
Option 5	$585	$240	$246	$678	$282	$395
Option 6	$581	$246	$256	$690	$296	$437
Option 7	$725	$260	$262	$689	$296	$355
Option 8	$799	$273	$283	$716	$328	$433
Option 9	$794	$278	$293	$730	$341	$471
Option 10	$508	$355	$179	$668	$365	$679
Option 11	$582	$366	$200	$696	$396	$758
Option 12	$577	$370	$213	$710	$411	$793
Option 13	$607	$393	$227	$717	$427	$731
Option 14	$681	$404	$247	$745	$457	$807
Option 15	$676	$409	$259	$758	$470	$842
Option 16	$821	$423	$272	$761	$479	$771
Option 17	$894	$434	$290	$787	$509	$845
Option 18	$890	$438	$298	$799	$521	$880
Option net benefits PV $m						
		Scenario				
Shortlisted option		Global	Reference	Growth	Environmental	Disruptive
Option 1		-$226	-$233	$190	-$221	-$142
Option 2		-$286	-$283	$147	-$259	-$140
Option 3		-$277	-$269	$163	-$240	-$91
Option 4		-$285	-$288	$138	-$263	-$193
Option 5		-$345	-$339	$93	-$303	-$190
Option 6		-$335	-$325	$109	-$285	-$144
Option 7		-$465	-$463	-$36	-$429	-$370
Option 8		-$526	-$516	-$83	-$471	-$366
Option 9		-$516	-$501	-$64	-$453	-$323
Option 10		-$153	-$329	$160	-$143	$171
Option 11		-$216	-$382	$114	-$186	$176
Option 12		-$207	-$364	$133	-$166	$216
Option 13		-$214	-$380	$110	-$180	$124
Option 14		-$277	-$434	$64	-$224	$126
Option 15		-$267	-$417	$82	-$206	$166
Option 16		-$398	-$549	-$60	-$342	-$50
Option 17		-$460	-$604	-$107	-$385	-$49
Option 18		-$452	-$592	-$91	-$369	-$10

Table 19: Net benefit of shortlist of HVDC and CNI and Wairakei Ring options with balanced scenario weightings

Net benefit of shortlist of HVDC and CNI and Wairakei Ring options with various scenario weightings, $PV net benefit, $m				
Scenario weighting	Weighting set 1 20/20/20/20/20	Weighting set 2 5/10/25/30/30	Weighting set 3 0/10/30/30/30	Preferred weighting set 4 0/0/33/33/33
Shortlisted option				
Option 1	-$126	-$96	-$75	-$57
Option 2	-$164	-$126	-$104	-$84
Option 3	-$143	-$99	-$77	-$56
Option 4	-$178	-$145	-$124	-$106
Option 5	-$217	-$176	-$154	-$134
Option 6	-$196	-$150	-$128	-$106
Option 7	-$353	-$319	-$297	-$279
Option 8	-$392	-$350	-$328	-$307
Option 9	-$372	-$325	-$303	-$280
Option 10	-$59	$8	$23	$63
Option 11	-$98	-$23	-$7	$35
Option 12	-$78	$1	$18	$61
Option 13	-$108	-$38	-$22	$18
Option 14	-$149	-$70	-$53	-$11
Option 15	-$128	-$47	-$29	$14
Option 16	-$279	-$207	-$190	-$150
Option 17	-$321	-$241	-$223	-$181
Option 18	-$303	-$218	-$200	-$156

Table 20: Net benefit of shortlist of HVDC and CNI and Wairakei Ring options with various scenario weighting

We note that several of the options do not reach a positive net benefit under any of our scenario weighting sets.

Our preferred option for upgrading the existing grid, from Table 20, is the option which passes the Investment Test with our preferred weighting set 4 – option 10, which includes:

Preferred option				
	Stage 1 MCP		**Stage 2 MCP**	
	Project	Approx. cost, $m	Project	Approx. cost, $m
HVDC	New reactive support at Haywards	128	New Cook Strait cable	120
CNI	TTU/duplex TKU-WKM A&B lines, TTU BPE-TKU A&B lines	182		
Wairakei Ring	TTU WRK-WKM C line	13		

Table 20A: Preferred option

Although not previously discussed, we recommend uprating the HVDC capacity to 1400 MW, in two stages, with Stage 1 (to be included in this MCP) being to increase the availability of the existing HVDC equipment at 1200 MW and Stage 2 (the next NZGP1 MCP) being to install a new Cook Strait cable and increase HVDC transfer capacity to 1400 MW.

The existing Cook Strait cables are projected to reach end of life in 2032 and given the earliest we could lay new Cook Strait cable is 2027, given availability of suitable shipping, we are currently evaluating whether to replace all cables at the same time and whether the cables should be 500 MW or 700 MW. We hope to have resolved that question by the time we submit this MCP to the Commission, but even so increasing Cook Strait cable capacity will still be a Stage 2 MCP.

Q9. Is our choice of the preferred option reasonable?

4.55 Bypassing the existing grid

How does our preferred option for upgrading the existing grid compare to options which bypass the existing grid altogether? We identified two potential options to consider, as listed in long-list Table 5. These both include building new HVDC links between different parts of the grid.

A high-level cost comparison between our preferred option for upgrading the existing grid and those two options demonstrates that upgrading the existing grid is more economic. We have not analysed the benefit differences between the options. Installing new HVDC links would provide a considerable resilience benefit overall, as they provide a new transport route between important parts of the transmission grid, but in our view that benefit would not outweigh the higher cost.

Option	High level cost, $b	Comments
Upgrade existing grid - preferred	$1.3	Includes all Stage 1 and 2 costs
New North Island HVDC Option	$2.0	Requires new HVDC line from HAY to WKM plus new HVDC converters at WKM
New inter-island HVDC Option	$4.0	Requires new HVDC lines in North and South Island plus new HVDC converters in South Island and HLY, pus new inter-island cables

Table 20B: Options to bypass the existing grid

Based on this high-level analysis our preferred option remains to upgrade the existing grid.

Q10. Is our conclusion that upgrading existing assets is more economic than bypassing the existing grid reasonable?

4.6 Investment Test Sensitivities

In order to test the economic robustness of our preferred option, the Capex IM requires that we undertake sensitivity analysis to potentially significant parameters.

For this application of the Investment Test we consider the following sensitivities relevant:

Parameter sensitised	Comment
Report result by scenario	Reported in Table 19
Scenario weightings	Reported in Table 20
Capital cost of preferred option	The capital costs are varied +/-30% relative to other options
Ongoing cost of preferred option	The ongoing costs are varied +/-30% compared to other options
Value of expected unserved energy	$10,000 and $35,000 are reported
Discount rate	Sensitivities of 4% and 10% are compared
Electricity demand growth	The WiTMH highest demand forecast – Mobilise to Decarbonise is compared
Tiwai closure date	A closure date of 2030 is compared

Table 21: Investment test sensitivities to be reported

As per Table 21, the Investment Test results by scenario and using different scenario weightings are reported in Tables 22 and 23 respectively.

Table 22 reports the sensitivity of expected net market benefit to a 30% reduction in capital cost for the preferred option.

Sensitivity of expected net benefit of shortlist of HVDC and CNI and Wairakei Ring options with various scenario weightings to -30% capital cost $PV net benefit, $m				
Scenario weighting	Weighting set 1 20/20/20/20/20	Weighting set 2 5/10/25/30/30	Weighting set 3 0/10/30/30/30	Preferred weighting set 4 0/0/33/33/33
Shortlisted option				
Option 1	-$126	-$96	-$75	-$57
Option 2	-$164	-$126	-$104	-$84
Option 3	-$143	-$99	-$77	-$56
Option 4	-$178	-$145	-$124	-$106
Option 5	-$217	-$176	-$154	-$134
Option 6	-$196	-$150	-$128	-$106
Option 7	-$353	-$319	-$297	-$279
Option 8	-$392	-$350	-$328	-$307
Option 9	-$372	-$325	-$303	-$280
Option 10	-$55	$11	$27	$66
Option 11	-$98	-$23	-$7	$35
Option 12	-$78	$1	$18	$61

Option 13	-$108	-$38	-$22	$18
Option 14	-$149	-$70	-$53	-$11
Option 15	-$128	-$47	-$29	$14
Option 16	-$279	-$207	-$190	-$150
Option 17	-$321	-$241	-$223	-$181
Option 18	-$303	-$218	-$200	-$156

Table 22: Sensitivity of expected net benefit of shortlist of HVDC and CNI and Wairakei Ring options with various scenario weightings to -30% capital cost

As observed in Table 22, the preferred option does not change in this sensitivity. To be "similar", the 10% parameter would need to change to 15% to include option 15.

Table 23 reports the sensitivity of expected net market benefit to a 30% increase in capital cost for the preferred option.

Sensitivity of expected net benefit of shortlist of HVDC and CNI and Wairakei Ring options with various scenario weightings to +30% capital cost $PV net benefit, $m				
Scenario weighting	Weighting set 1 20/20/20/20/20	Weighting set 2 5/10/25/30/30	Weighting set 3 0/10/30/30/30	Preferred weighting set 4 0/0/33/33/33
Shortlisted option				
Option 1	-$126	-$96	-$75	-$57
Option 2	-$164	-$126	-$104	-$84
Option 3	-$143	-$99	-$77	-$56
Option 4	-$178	-$145	-$124	-$106
Option 5	-$217	-$176	-$154	-$134
Option 6	-$196	-$150	-$128	-$106
Option 7	-$353	-$319	-$297	-$279
Option 8	-$392	-$350	-$328	-$307
Option 9	-$372	-$325	-$303	-$280
Option 10	-$61	$5	$21	$60
Option 11	-$98	-$23	-$7	$35
Option 12	-$78	$1	$18	$61
Option 13	-$108	-$38	-$22	$18
Option 14	-$149	-$70	-$53	-$11
Option 15	-$128	-$47	-$29	$14
Option 16	-$279	-$207	-$190	-$150
Option 17	-$321	-$241	-$223	-$181
Option 18	-$303	-$218	-$200	-$156

Table 23: Sensitivity of expected net benefit of shortlist of HVDC and CNI and Wairakei Ring options with various scenario weightings to +30% capital cost

As observed in Table 23, the highest expected net market benefit now applies to option 12, but only marginally. Option 10 is still "similar" and would remain our preferred option. To be "similar", the 10% parameter would need to change to 15% to include option 15.

Table 24 reports the sensitivity of expected net market benefit to a 30% reduction in ongoing (maintenance) costs for the preferred option.

Sensitivity of expected net benefit of shortlist of HVDC and CNI and Wairakei Ring options with various scenario weightings to -30% ongoing costs $PV net benefit, $m				
Scenario weighting	Weighting set 1 20/20/20/20/20	Weighting set 2 5/10/25/30/30	Weighting set 3 0/10/30/30/30	Preferred weighting set 4 0/0/33/33/33
Shortlisted option				
Option 1	-$126	-$96	-$75	-$57
Option 2	-$164	-$126	-$104	-$84
Option 3	-$143	-$99	-$77	-$56
Option 4	-$178	-$145	-$124	-$106
Option 5	-$217	-$176	-$154	-$134
Option 6	-$196	-$150	-$128	-$106
Option 7	-$353	-$319	-$297	-$279
Option 8	-$392	-$350	-$328	-$307
Option 9	-$372	-$325	-$303	-$280
Option 10	-$54	$12	$28	$67
Option 11	-$98	-$23	-$7	$35
Option 12	-$78	$1	$18	$61
Option 13	-$108	-$38	-$22	$18
Option 14	-$149	-$70	-$53	-$11
Option 15	-$128	-$47	-$29	$14
Option 16	-$279	-$207	-$190	-$150
Option 17	-$321	-$241	-$223	-$181
Option 18	-$303	-$218	-$200	-$156

Table 24: Sensitivity of expected net benefit of shortlist of HVDC and CNI and Wairakei Ring options with various scenario weightings to -30% ongoing cost

As observed in Table 24, the highest expected net market benefit applies to option 10 and this option would remain our preferred option. To be "similar", the 10% parameter would need to change to 15% to include option 15.

Table 25 reports the sensitivity of expected net market benefit to a 30% increase in ongoing (maintenance) costs for the preferred option.

Sensitivity of expected net benefit of shortlist of HVDC and CNI and Wairakei Ring options with various scenario weightings to +30% ongoing costs $PV net benefit, $m				
Scenario weighting	Weighting set 1 20/20/20/20/20	Weighting set 2 5/10/25/30/30	Weighting set 3 0/10/30/30/30	Preferred weighting set 4 0/0/33/33/33
Shortlisted option				
Option 1	-$126	-$96	-$75	-$57
Option 2	-$164	-$126	-$104	-$84
Option 3	-$143	-$99	-$77	-$56
Option 4	-$178	-$145	-$124	-$106
Option 5	-$217	-$176	-$154	-$134
Option 6	-$196	-$150	-$128	-$106
Option 7	-$353	-$319	-$297	-$279
Option 8	-$392	-$350	-$328	-$307
Option 9	-$372	-$325	-$303	-$280
Option 10	-$62	$4	$20	$59
Option 11	-$98	-$23	-$7	$35
Option 12	-$78	$1	$18	$61
Option 13	-$108	-$38	-$22	$18
Option 14	-$149	-$70	-$53	-$11
Option 15	-$128	-$47	-$29	$14
Option 16	-$279	-$207	-$190	-$150
Option 17	-$321	-$241	-$223	-$181
Option 18	-$303	-$218	-$200	-$156

Table 25: Sensitivity of expected net benefit of shortlist of HVDC and CNI and Wairakei Ring options with various scenario weightings to +30% ongoing costs

As observed in Table 25, the highest expected net market benefit now applies to option 12, but only marginally. Option 10 is still “similar” and would remain our preferred option.

Table 26 reports the sensitivity of expected net market benefit to a 4% discount rate being applied rather than 7%.

Sensitivity of expected net benefit of shortlist of HVDC and CNI and Wairakei Ring options with various scenario weightings to 4% discount rate PV net benefit, $m				
Scenario weighting	Weighting set 1 20/20/20/20/20	Weighting set 2 5/10/25/30/30	Weighting set 3 0/10/30/30/30	Preferred weighting set 4 0/0/33/33/33
Shortlisted option				
Option 1	-$173	-$136	-$110	-$88
Option 2	-$214	-$166	-$140	-$115
Option 3	-$189	-$135	-$108	-$81
Option 4	-$207	-$167	-$140	-$118
Option 5	-$249	-$199	-$171	-$146
Option 6	-$225	-$169	-$141	-$114
Option 7	-$465	-$422	-$396	-$373
Option 8	-$507	-$455	-$427	-$401
Option 9	-$484	-$426	-$398	-$370
Option 10	-$84	-$1	$18	$67
Option 11	-$127	-$33	-$13	$39
Option 12	-$103	-$5	$16	$69
Option 13	-$115	-$28	-$8	$41
Option 14	-$159	-$62	-$41	$12
Option 15	-$136	-$34	-$12	$41
Option 16	-$368	-$279	-$258	-$208
Option 17	-$414	-$314	-$292	-$239
Option 18	-$392	-$287	-$265	-$211

Table 26: Sensitivity of expected net benefit of shortlist of HVDC and CNI and Wairakei Ring options with various scenario weightings to 4% discount rate

As observed in Table 26, the highest expected net market benefit now applies to option 12, but only marginally. Option 10 is still “similar” and would remain our preferred option. To be “similar”, the 10% parameter would need to change to 15% to include option 14.

Table 27 reports the sensitivity of expected net market benefit to a 10% discount rate being applied rather than 7%.

Sensitivity of expected net benefit of shortlist of HVDC and CNI and Wairakei Ring options with various scenario weightings to 10% discount rate $PV net benefit, $m				
Scenario weighting	Weighting set 1 20/20/20/20/20	Weighting set 2 5/10/25/30/30	Weighting set 3 0/10/30/30/30	Preferred weighting set 4 0/0/33/33/33
Shortlisted option				
Option 1	-$100	-$75	-$58	-$43
Option 2	-$135	-$103	-$85	-$68
Option 3	-$116	-$80	-$62	-$44
Option 4	-$155	-$127	-$110	-$95
Option 5	-$190	-$156	-$138	-$121
Option 6	-$172	-$134	-$116	-$97
Option 7	-$280	-$251	-$233	-$218
Option 8	-$315	-$280	-$261	-$244
Option 9	-$297	-$259	-$240	-$221
Option 10	-$47	$9	$22	$54
Option 11	-$82	-$20	-$6	$28
Option 12	-$65	$1	$15	$50
Option 13	-$99	-$41	-$28	$5
Option 14	-$136	-$71	-$56	-$21
Option 15	-$118	-$50	-$36	-$0
Option 16	-$221	-$161	-$147	-$114
Option 17	-$259	-$192	-$177	-$142
Option 18	-$242	-$172	-$157	-$121

Table 27: Sensitivity of expected net benefit of shortlist of HVDC and CNI and Wairakei Ring options with various scenario weightings to 10% discount rate

As observed in Table 27, the preferred option does not change in this sensitivity. To be “similar”, the 10% parameter would need to change to 15% to include option 15.

Sensitivity of expected net benefit of short list options using various scenario weightings to comparison with a high demand scenario, $PV net benefit, $m				
Scenario weighting	Mobilise to Decarbonise scenario	Weighting set 2 5/10/25/30/30	Weighting set 3 0/10/30/30/30	Preferred weighting set 4 0/0/33/33/33
Short list option				
Option 1		-$96	-$75	-$57
Option 2		-$126	-$104	-$84
Option 3		-$99	-$77	-$56
Option 4		-$145	-$124	-$106
Option 5		-$176	-$154	-$134
Option 6		-$150	-$128	-$106
Option 7		-$319	-$297	-$279
Option 8		-$350	-$328	-$307
Option 9		-$325	-$303	-$280
Option 10	$48	$8	$23	$63
Option 11	$45	-$23	-$7	$35
Option 12	$67	$1	$18	$61
Option 13	-$7	-$38	-$22	$18
Option 14	-$13	-$70	-$53	-$11
Option 15	$9	-$47	-$29	$14
Option 16	-$181	-$207	-$190	-$150
Option 17	-$195	-$241	-$223	-$181
Option 18	-$180	-$218	-$200	-$156

Table 28: Sensitivity of expected net benefit of shortlist of HVDC and CNI and Wairakei Ring options with various scenario weightings to high demand scenario

As observed in Table 28, the use of a high demand scenario gives expected net market benefits similar to those in our preferred weighting set 4. The highest expected net market benefit is for option 12, but option 10 would be considered "similar" and would remain our preferred option.

All of these sensitivities show that the ranking of options is robust. In some sensitivities option 10 and option 12 change places, but in those sensitivities option 10 would still be considered "similar".

We conclude that our choice of preferred option is robust to sensitivity analysis.

Q11. Do you agree that our choice of preferred option is robust against sensitivity analysis?

4.7 Scenario sensitivities

Whilst the Investment Test scenarios test the robustness of the preferred option to a wide range of Investment Test parameters, the electricity industry currently faces a wide range of uncertainties not reflected in either the scenarios or sensitivities.

For further comparison, we have developed a set of potential futures which may affect the configuration of the grid if they emerged but are not yet certain enough to reflect in our EDGS variations. These are described briefly in Table 29:

Potential future		
	Sensitivity scenario	Description
1	No Southland load replacement	Tiwai closes in 2030, with no replacement load in Southland. This sensitivity scenario has been evaluated as an Investment Test sensitivity.
2	Southland load partially replaced[25]	Tiwai closes in 2030, but is replaced by a 300 MW hydrogen plant which can provide flexible demand response
3	Southland load replaced	Tiwai closes in 2030, but is replaced by a 600 MW hydrogen plant which can provide flexible demand response
4	High demand	Higher than anticipated electrification occurs. This is reflected in our WiTMH Mobilise to Decarbonise scenario which reflects the maximum extent of electrification. In 2050 electricity demand is 72 TWh. This sensitivity scenario has been evaluated as an Investment Test sensitivity.
5	South Island dry year solution	Lake Onslow is developed and provides dry year security of supply and competes in the wholesale market
6	Hydrogen future	Hydrogen becomes a viable zero carbon fuel, with North Island gas primarily replaced by hydrogen
7	Taranaki offshore wind	Taranaki offshore wind is developed
8	Taranaki demand grows	Taranaki region recovers from gas closures with new industry developed
9	Wind:solar generation mix 50:50	Grid-scale solar generation is developed more than anticipated in our scenarios. We test a 50:50 wind:solar future
10	Climate change effects	Climate change effects on hydro/wind and solar profiles are considered

Table 29: Sensitivity Scenarios

[25] There are other options where new generation is built in Southland as well, but the net result is the same as in this set of sensitivity scenarios.

It is neither plausible, nor necessary in most instances, to scope out what the transmission grid might look like if any of these futures emerged, but we can evaluate what flows over those parts of the transmission network covered by this MCP would look like if they did.

This will provide further information on whether our preferred option is robust to these alternative futures.

We have not been able to explore these futures at this time, but will by the time we submit a MCP to the Commission late in 2022.

Other components of NZGP1 MCP

Our preferred option passes the Investment Test, presuming our recommendations on EDGS variations, the use of the 10% similarity rule and variation of scenario weightings from all scenarios being equal are accepted.

Our intention, subject to consultation, is to include our preferred option in a NZGP1 MCP Stage 1. There will also be other components to be included in the Stage 1 MCP and these are discussed below.

4.71 Facilitating projects

As discussed in section 1.14, there are several, smaller grid constraints which need to be relieved in order to enable our preferred option. We call these facilitating projects and the reasons for undertaking them is described in section 1.14. They are required to enable higher grid flows over either the CNI lines or the Wairakei Ring.

Adding these to the preferred option table, starts to better describe the contents of our Stage MCP:

List of NZGP1 projects				
Preferred option – upgrade projects				
	Stage 1 MCP		Stage 2 MCP	
	Project	Approx. cost $m	Project	Approx. cost $m
HVDC	New reactive support at Haywards	128	New Cook Strait cable	120
CNI	TTU/duplex TKU-WKM A&B lines, TTU BPE-TKU A&B lines	182		
Wairakei Ring	TTU WRK-WKM C line	13		
Preferred option – facilitating projects				
BPE_ONG 110kV split	Split Bunnythorpe-Ongarue 110 kV line at Ongarue	0.5		
HLY-SFD protection	Replace protection on the Huntly-Stratford 220 kV line	2.0		
Replace TKU SPS	Replace the SPS in place at Tokaanu	1.0		
EDG-KAW 110kV split	Split Edgecumbe-Kawerau 110 kV line	0.5		
EDG-KAW 220kV TTU	TTU Edgecumbe-Kawerau 220kV line	5.0		

BRK-SFD reconductor	Investigate upgrade options for BRK-SFD lines	2.0	Reconductor Brunswick - Stratford 220 kV A line	75

Table 30: List of NZGP facilitating projects

4.72 Preparedness projects

As discussed in section 4.51 and 4.52, our preferred option increases CNI and Wairakei Ring capacity incrementally. We believe it is in consumers interests that we continue to prepare for those other short-list options which maximise the capacity of existing grid assets and those options which provide entirely new capacity.

We know the Investment Test prefers just-in-time, incremental options, which in some circumstances is appropriate. However, if we accept those options only, we will be restricting the ability of future investors to build only in the limited number of places where there is spare transmission grid capacity.

If we are not satisfied with that, we could "go big" i.e., build new transmission capacity in a similar vein to the work our predecessors accomplished in the 1950's, when large amounts of generation expansion was undertaken to match forecasted demand increases; and transmission build was required to meet the rapid growth.

Economics now dominates in our investment decision-making and "going big" on the basis of "build and they shall come" does not fit well with traditional economic approaches. Having said that, previous transmission grid decision-makers did make sound decisions and we have benefitted from those decisions.

A middle ground which balances risks for consumers is to build in accordance with the Investment Test, but hedge bets on different futures requiring more transmission capacity by spending money to develop plans which can then sit on the shelf, but be rolled out at short notice if they appear appropriate.

For NZGP1 that approach translates to:

- Developing detailed designs for the duplexing of the existing BPE-TKU A&B lines
- Developing detailed designs for the thermal upgrading of the BPE-WRK A line
- Taking forward plans to build a new line north of Bunnythorpe
- Taking forward plans to either replace the WRK-WKM A line, or build a new WRK-WKM D line

The detailed designs for upgrading the existing CNI lines would then be ready to go at short notice, if futures emerge which require more CNI capacity, in a similar manner to the CUWLP plans we developed and had ready for those lines.

In terms of developing new lines, we would:

Improve our understanding of resilience benefits

There are four existing 220kV lines that head north from our Bunnythorpe substation:

BPE-BRK-SFD-HLY
BPE- WKM A&B
BPE-WRK A

Three of these lines follow a similar path to Rangipo, where one deviates to Wairakei while the other two follow closely to Whakamaru. These three lines are susceptible to volcanic risk from Ruapehu and/or Tongariro. We mitigate this risk via the use of specially designed equipment on out towers in this region, but there remains a risk.

If we do build a new line north of Bunnythorpe, there are three distinctly different routes it could take. One would follow west, potentially on a similar route to our BPE-BRK-SFD-HLY 220kV line. One would follow through the centre of the North Island, on a similar route to our BPE-WKM A&B lines. The third would proceed east into the northern Wairarapa and up to Hawkes Bay.

These routes are geographically diverse and have advantages and disadvantages from a system point of view, but also they have different resilience characteristics. Going east through the Hawkes Bay would diversify the risk from volcanic activity, for instance, among other benefits such as providing a second supply route into the Hawkes Bay.

Apart from being able to quantify the benefit of having more redundancy in the transmission network, we are currently unable to quantify the benefits resilience diverse routes have for security of supply from natural disasters. We believe these benefits may be significant and could influence an investment decision to build a new transmission line.

Our MCP will include funding to explore approaches to quantifying the resilience benefits of diverse transmission routes and risks due to natural disasters. We would look to employ appropriate expertise to help with this.

Investigate routes for new lines

Move as far as possible toward developing detailed designs for a new line. This might involve undertaking as much of an ACRE process as possible and might involve preliminary discussions with landowners.

Undertaking this preliminary work now would allow Transpower to respond more quickly should a future start to emerge that might require a new line.

In our view, undertaking preparedness such as these studies balances the risks of building incrementally, future uncertainty and being as ready as possible to implement other solutions at short notice.

Adding these to Table 30, shows a more complete picture of how Transpower considers an appropriate response to dealing with such future uncertainty, yet wanting to enable our net zero carbon by 2050 goal, looks:

List of NZGP1 projects				
Preferred option – upgrade projects				
	Stage 1 MCP		Stage 2 MCP	
	Project	Approx. cost $m	Project	Approx. cost $m
HVDC	New reactive support at Haywards	128	New Cook Strait cable	120
CNI	TTU/duplex TKU-WKM A&B lines, TTU BPE-TKU A&B lines	182		
Wairakei Ring	TTU WRK-WKM C line	13		
Preferred option – facilitating projects				
BPE_ONG 110kV split	Split Bunnythorpe-Ongarue 110 kV line at Ongarue	0.5		
HLY-SFD protection	Replace protection on the Huntly-Stratford 220 kV line	2.0		
Replace TKU SPS	Replace the SPS in place at Tokaanu	1.0		
EDG-KAW 110kV split	Split Edgecumbe-Kawerau 110 kV line	0.5		
EDG-KAW 220kV TTU	TTU Edgecumbe-Kawerau 220kV line	5.0		
BRK-SFD reconductor		2.0	Reconductor Brunswick - Stratford 220 kV A line	75
Preparedness projects				
BPE-TKU duplexing	Detailed designs for duplexing BPE-TKU A&B lines	1.5		
BPE-WRK TTU	Detailed designs for a TTU of the BPW-WRK A line	0.5		
BPE new line	Investigate routes and detailed design for new BPE north 220 kV line	3.0		
Wairakei Ring new line	Investigate routes and detailed design for new WRK-WKM line, or replacement of existing WRK-WKM A line	2.0		
Quantifying resilience methodology	Develop a methodology to quantify the resilience benefits of various options	0.3		

Table 31: List of NZGP projects including preparedness projects

4.73 Further investigations

Lastly, there were two other issues which arose during our NZGP1 investigation which require further investigation. They relate to other grid constraints that might need to be addressed and a critical failure risk at a key substation.

As mentioned throughout the document, our studies to date have focussed on the need for thermal capacity, particularly in our CNI corridor and on the Wairakei Ring. We have identified upgrades which are economic to implement and have identified several facilitating projects which are required to ensure other thermal constraints do not limit the useability of those upgrades. Additionally, we need to undertake voltage stability studies to ensure voltage stability limits will not bind and limit the useability of those upgrades.

We have recently completed a lower North Island motor load survey and this will provide crucial information to enable the voltage stability studies.

Our NZGP1 MCP stage 1 will include a request for funding to undertake the voltage stability studies.

In the course of this investigation, it was recognised that our Bunnythorpe substation may become a single point of failure on the transmission network if we continue to add transfer capacity in and out of Bunnythorpe. It would be prudent to undertake a study to understand the risks at Bunnythorpe and explore mitigating approaches such as diversifying some of the load throughput to another substation.

Our NZGP1 MCP Stage 1 will include a request for funding to undertake a Bunnythorpe diversification study.

By adding these two elements, we complete our NZGP1 MCP.

List of NZGP1 projects				
Preferred option – upgrade projects				
	Stage 1 MCP		Stage 2 MCP	
	Project	Approx cost $m	Project	Approx cost $m
HVDC	New reactive support at Haywards	128	New Cook Strait cable	120
CNI	TTU/duplex TKU-WKM A&B lines, TTU BPE-TKU A&B lines	182		
Wairakei Ring	TTU WRK-WKM C line	13		
Preferred option – facilitating projects				
BPE_ONG 110kV split	Split Bunnythorpe-Ongarue 110 kV line at Ongarue	0.5		
HLY-SFD protection	Replace protection on the Huntly-Stratford 220 kV line	2.0		
Replace TKU SPS	Replace the SPS in place at Tokaanu	1.0		
EDG-KAW 110kV split	Split Edgecumbe-Kawerau 110 kV line	0.5		
EDG-KAW 220kV TTU	TTU Edgecumbe-Kawerau 220kV line	5.0		

BRK-SFD reconductor	Investigate upgrade options for BRK-SFD lines	2.0	Reconductor Brunswick - Stratford 220 kV A line	75
Preparedness projects				
BPE-TKU duplexing	Detailed designs for duplexing BPE-TKU A&B lines	1.5		
BPE-WRK TTU	Detailed designs for a TTU of the BPW-WRK A line	0.5		
BPE new line	Investigate routes and detailed design for new BPE north 220 kV line	3.0		
Wairakei Ring new line	Investigate routes and detailed design for new WRK-WKM line, or replacement of existing WRK-WKM A line	2.0		
Quantifying resilience methodology	Develop a methodology to quantify the resilience benefits of various options	0.3		
Further investigations				
Lower North Island voltage stability study	Investigate voltage stability in the lower North Island	0.2		
Bunnythorpe diversification investigation	Investigate whether we should diversify Bunnythorpe throughput	0.3		

Table 3218: List of NZGP projects including further investigations

Appendix A - Scenarios

A1 EDGS 2019

The EDGS 2019 include five scenarios as follows:

6. Reference: Current trends continue

   The "Current trends continue" scenario is scenario is one view of how the electricity system could evolve under current policies and technology trends if no major changes occur.

7. Growth: Accelerated economic growth

   This scenario assumes the past decade of slow growth in labour productivity is an aberration rather than the norm. Higher economic growth drives higher immigration while policy and investment focus on priorities other than the energy sector. The economy is transformed to put emphasis on high technology. The commercial sector grows to be larger than in the Reference scenario and higher income growth leads to higher uptake of electric vehicles. This scenario provides an assessment of what level electricity demand could reach if the economy is doing well.

8. Global: International economic changes

   In this scenario New Zealand's economy is battered by international trends, leaving little room for local growth or innovation. Some aspects are opposite to the Accelerated economic growth scenario such as the uptake of EVs. This scenario also includes a higher cost for wind turbines and solar power than in the Reference scenario.

9. Environmental: Sustainable transition

   The New Zealand government targets more ambitious emissions reduction levels than in the Reference scenario. Strong environmental leadership, including the use of regulation and incentives (rather than technology) provides the change reflected in this scenario. Policies are introduced to support the electrification of both transport and process heat. This scenario focuses on decarbonising the economy.

10. Disruptive: Improved technologies are developed

    In this scenario, the electricity demand and supply implications of more advanced and sophisticated technological progress in the energy sector are reflected. A faster reduction in technology costs results in a higher uptake of both EVs and solar more electrification of process heat.

Figure 13 shows the EDGS 2019 national demand[26] forecasts by scenario, but with Tiwai exiting in 2024.

[26] The EDGS reports gross national demand, being the total electricity used by consumers. It is defined as electricity demand measured as exiting the grid at our GXP's' less distribution losses plus generation embedded behind our GXP's. Our EDGS 2019 variations also report gross national demand.

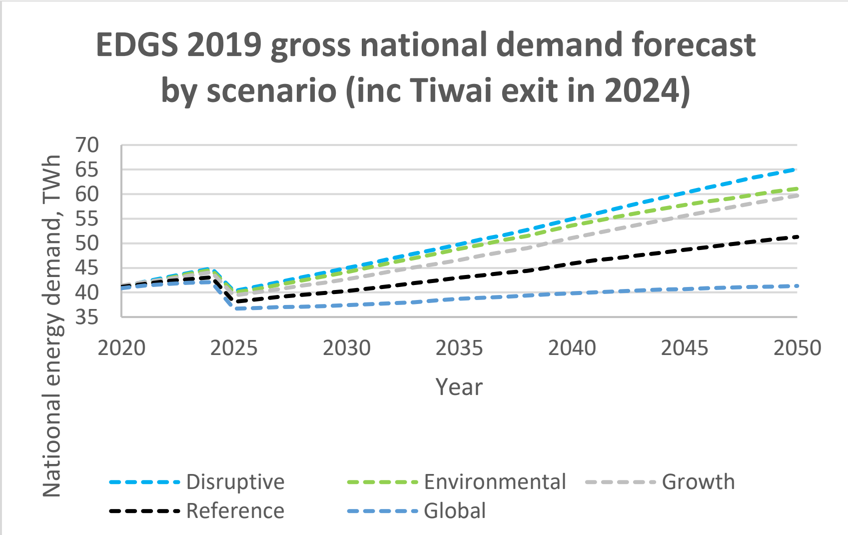

Figure 13: EDGS 2019 national demand forecasts by scenario

1.1 Tiwai closure

In 2020 advice, Rio Tinto announced that the aluminium smelter at Tiwai had an electricity supply contract until the end of 2024 and its future after that was uncertain.

In November-December of that year, when reviewing the EDGS 2019, our expert panel was unanimous that we should assume Tiwai aluminium smelter would close at the end of 2024.

Global aluminium prices were low and the financial outlook for Tiwai was not positive. Within months, the global aluminium price had increased to a point where the financial outlook for Tiwai was looking positive and Rio Tinto were hinting that they wanted to remain past 2024.

Since then, aluminium prices have remained high, but Meridian and Contact have announced and progressed their plans for a large hydrogen production facility in Southland[27] and Rio Tinto have made their plans for Tiwai closure at the end of 2024, public[28].

We could speculate on whether the aluminium smelter will close, or stay, at the end of 2024, but that is all it would be – speculation.

We have taken a prudent approach in our NZGP1 investigation and assumed that Tiwai does close at the end of 2024. That is based on the only known information we have - that Tiwai only has a supply contract until then. It is prudent because, if Tiwai does close and there is no replacement load in Southland, then the existing transmission grid would constrain a portion of Manapouri's generation from being dispatched. Although we cannot have plans in place to fully dispatch Manapouri in 2025, we can develop a plan which enables that possibility within 2-3 years.

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[27] www.southerngreenhydrogen.co.nz

[28] In March 2022 NZAS released their preliminary closure plan for Tiwai point, which detailed a closure date of December 2024 https://www.nzas.co.nz/files/3637_20220406135631-1649210191.pdf

We will undertake a sensitivity where Tiwai closes in 2030, rather than 2024, in order to understand whether our prudent assumption would affect the preferred option. The outcome of that sensitivity will be reported in any MCP application made to the Commission.

1.2 Identifying NZGP1 demand scenarios

We consulted with the industry on reasonable[29] variations to the EDGS 2019 demand forecasts, to ensure they were up to date and published these in December 2021, but since then, there have been other changes affecting our forward view of electricity demand, so we have incorporated made some minor adjustments We have:

- updated the historical data that informs our base load demand forecast
- updated our view of future demand at each Grid Exit Point (GXP) through discussion with our customers. This is a regular and annual process used to inform demand forecasts for our Transmission Planning Report. We discuss long term demand growth and demand step-changes as a result of known increases. The most significant change is in Auckland where some step-changes in new demand are occurring earlier than initially expected
- included replacement of the Marsden Point oil refinery by a storage terminal
- included retirement of Kawerau pulp and paper mill

Table 33 shows the original EDGS 2019 gross national demand forecast in 2050 (TWh), the changes included in the EDGS 2019 variations and the changes since then which make up our NZGP1 gross national demand forecast in 2050.

	EDGS scenario				
Gross national demand in 2050, TWh	**Reference**	**Growth**	**Global**	**Environmental**	**Disruptive**
EDGS 2019	57	65	47	67	71
Tiwai closure	-5	-5	-5	-5	-5
Variations due consultation	0	-4	2	-2	-2
EDGS 2019 variations	52	56	44	60	64
NZGP1 variations					
- Baseload forecast	-0.64	0.33	0.20	0.14	0.77
- Auckland step-jumps	0.45	0.45	0.45	0.45	0.45
- Marsden Point closure	-0.32	-0.32	-0.32	-0.31	-0.31
- Kawerau closure	-0.47	-0.47	-0.47	-0.46	-0.46
NZGP1	51	56	44	60	64

Table 33: Summary of EDGS scenarios

[29] The changes need to be considered reasonable in the sense that the revised EDGS 2019 forecasts can be used in place of the EDGS 2019 forecasts for evaluating investment decisions.

Diagrammatically, the original EDGS 2019 demand forecasts are shown in Figure 14 and Figure 15 along with our published EDGS 2019 variations and our proposed NZGP1 forecasts. Figure 14 shows the same data as in Figure 15, but all series are included on the same graph.

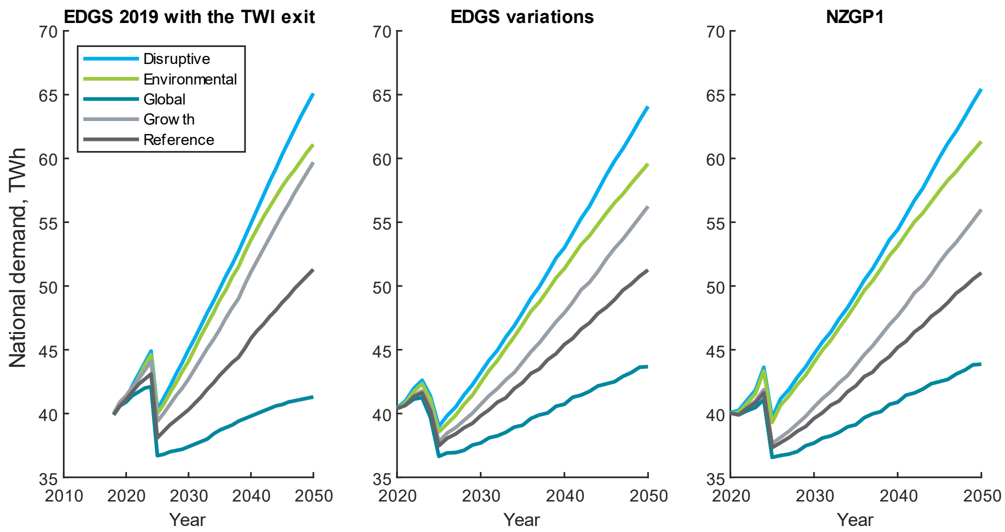


Figure 14: Comparison of the published EDGS 2019 (but with Tiwai exiting in 2024), our EDGS variations and proposed NZGP1 demand forecasts

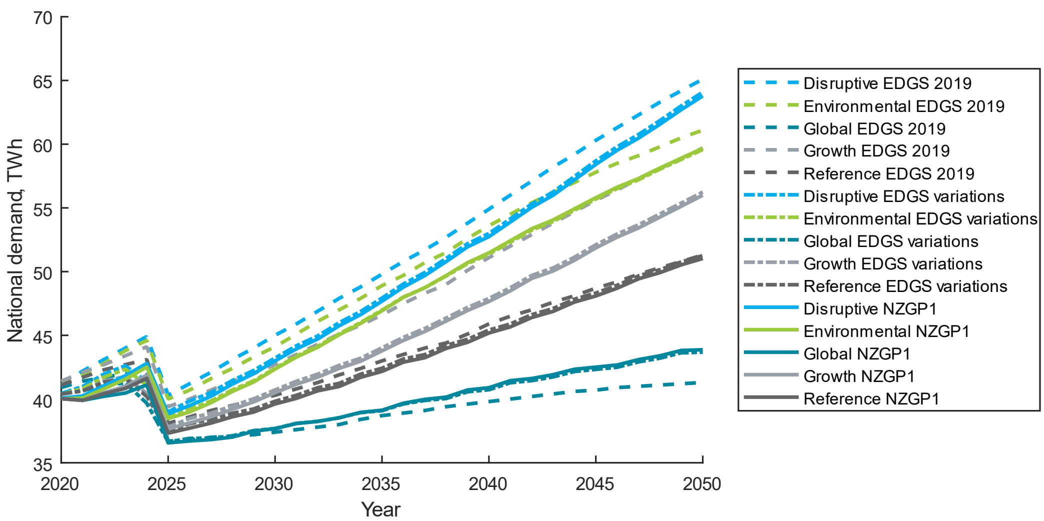


Figure 15: Comparison of the published EDGS 2019 (but with Tiwai exiting in 2024), our EDGS variations and proposed NZGP1 demand forecasts

1.21 Comparing the EDGS to other demand forecasts

Several New Zealand organisations produce electricity demand forecasts at present, focusing on different aspects of New Zealand's electricity future.

For comparison, we show our proposed NZGP1 demand forecasts with the Climate Change Commission's (CCC's) forecasts and Transpower's own Whakamana I Te Mauri Hiko (WiTMH) forecasts in Figure 16 below.

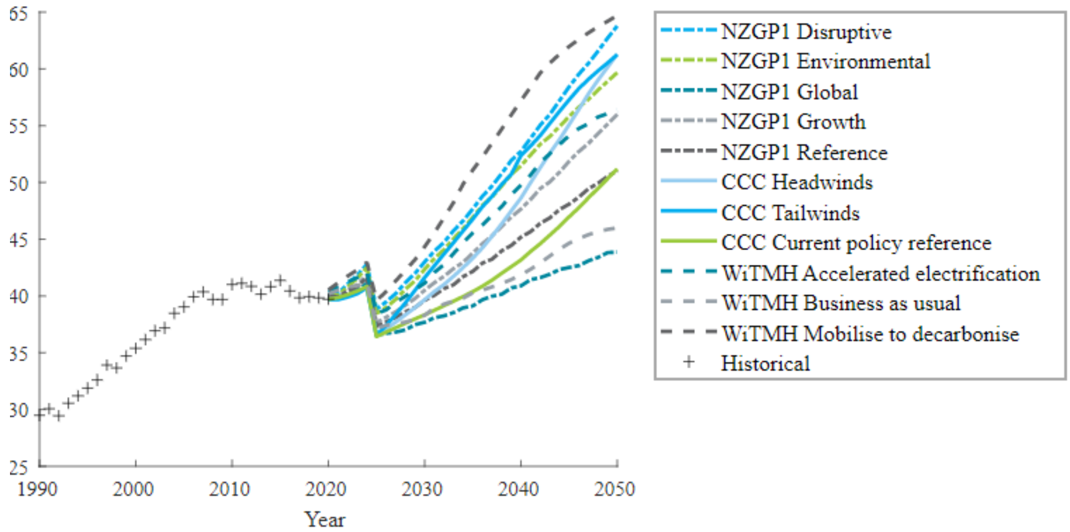


Figure 16: Comparison of NZGP1 demand forecasts, with CCC and WiTMH forecasts

We can make several interesting observations from Figure 16:

1) The range of gross national demand forecasts in our NZGP1 scenarios cover the full range of demand uncertainty between the other scenarios, excepting the WiTMH Mobilise to Decarbonise scenario.
2) We note that most of the EDGS, the CCC's Current Policy Reference scenario and the WiTMH Business as Usual scenario, are not aligned with a net zero carbon by 2050 target, whereas the other scenarios are. The weighted average demand of our NZGP1 forecasts (varied EDGS forecasts) is 55 TWh. The average of the CCC's aligned scenarios (Headwinds and Tailwinds) scenarios is 61 TWh and the weighted average of the WiTMH aligned scenarios (Accelerated electrification and Mobilise to decarbonize) scenarios is also 61 TWh.
3) Therefore, the national energy demand reflected in our Investment Test analysis will be below that forecast to be consistent with a net zero carbon by 2050 target as forecast by others.
4) However, we also note that the national energy demand forecast in the NZGP1 environmental scenario (varied EDGS) is 60 TWh and that this scenario is closely aligned with a net zero carbon by 2050 target.
5) In our Investment Test analysis, we will study and report each scenario separately, along with a sensitivity where the WiTMH Mobilise to Decarbonise scenario is reported as a sensitivity.

1.22 Solar PV forecasts

The difference between gross demand and GXP demand (which is primarily used in our analysis), is distribution losses and embedded generation. A part of the embedded generation is rooftop solar PV. We discussed the forecast uptake of solar PV in our panel meetings and decided to increase the uptake compared to EDGS 2019. For information and comparison, we show how our resultant NZGP1 solar PV forecasts compare with the original EDGS 2019 in Figure 17. The left plot shows the EDGS 2019 forecasts, and the right plot shows the variations that we consulted on along with the updated uptakes that we have used for NZGP1. The solid lines represent the NZGP1 forecast, and the dashed lines represent the EDGS 2019 variations.

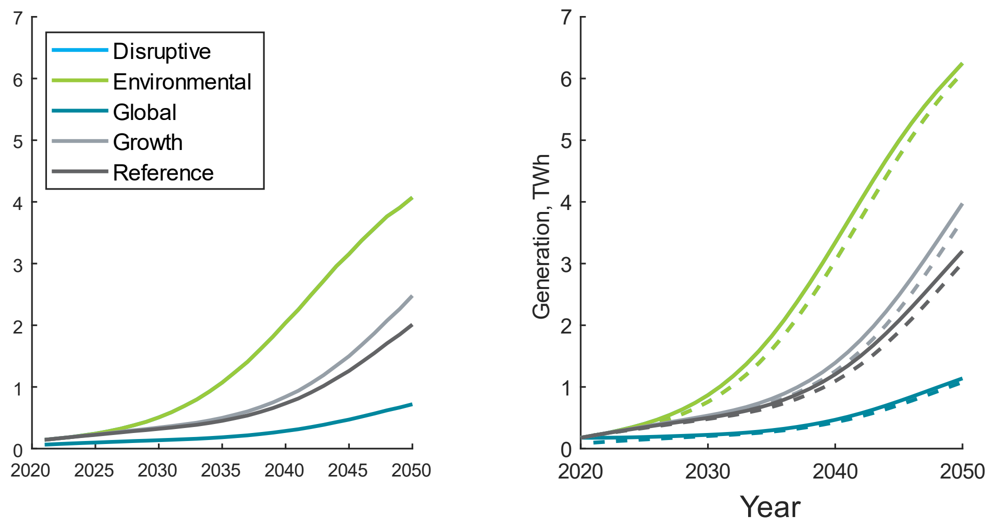


Figure 17: Solar demand for the three variations of the EDGS

1.3 NZGP1 generation scenarios

1.31 Generation cost stack

The generation stack is published by MBIE and used to assist with determining what electricity generation capacity is required to be built and when, to meet forecast electricity demand. MBIE updated the generation cost stack in 2020 and published five reports specific to different technologies:

- Geothermal
- Hydro (split between large-scale plants and embedded hydro opportunities)
- Thermal
- Utility scale solar
- Wind

These reports form the foundation of our generation expansion scenarios.

Notably the cost stack does not consider grid scale battery investments. For this reason, we have included data from the NREL Annual Technology Baseline which provides a consistent set of technology cost and performance data for energy analysis.

Furthermore, we have used the NREL Annual Technology Baseline to inform the future declines (taken as percentage decline from present day cost) in capital cost across all technologies. This is despite the MBIE reports containing varying degrees of commentary on this subject. We note that the scale and timing of future cost declines are particularly subjective. Our decision to use NREL estimates for future declines, rather than MBIE reports, is based on the argument that the NREL analysis is based on consistent assumptions across technologies and therefore should not introduce a technology bias. They are also the only source of data for grid scale batteries.

In accordance with the 2019 EDGS the following capital cost declines for each scenario have been set.

	Batteries	Solar	Wind	Geothermal
Global	Conservative	Conservative	Conservative	Conservative
Reference	Moderate	Moderate	Moderate	Moderate
Growth	Moderate	Moderate	Moderate	Moderate
Environmental	Moderate	Moderate	Moderate	Moderate
Disruptive	Advanced	Advanced	Conservative	Advanced

Table 34: Capital cost declines by scenario

The only departure was that we used the conservative cost decline trajectory for wind technology in the Disruptive scenario. This was done to create a scenario with a heavier bias toward solar technology. This was required because, as the cost stack numbers stand, wind technology was generally preferred within our least-cost expansion model due to higher capacity factors and lower overall costs.

1.32 Process for identifying an appropriate set of generation scenarios

Our primary approach to forecasting new generation is to use a least cost generation expansion model. Such a model uses the cost data (as identified in the preceding subsection) along with a demand forecast to identify a generation expansion plan which results in the lowest overall cost. This approach removes the need for discretion when deciding whether a given generation project will proceed or not. Furthermore, project cost is central to a developer's decision whether to proceed so our approach needs to capture that aspect of real-world decision making.

It is unreasonable for a model of this kind to accurately predict the future. What is important is that the scenarios are appropriate for the purpose of transmission planning and acceptable under the capex IM. To assess the appropriateness of our scenarios we consulted with generation investors in May 2021. The key feedback we received was:

- Solar developers are often a different type of investor than developers of other technology (for instance they may have different WACC).
- Solar developers claim benefits exist in solar which is not captured by a least-cost model (easier consenting and construction).
- Geothermal developers are looking at ways to innovate to stay competitive in a system with high carbon prices and cheap renewables.
- The situation is highly uncertain in terms of which regions offer the most attractive options.
- Investors are in the early stages of investigation into offshore wind in Taranaki.
- The gas industry is in the early stages of investigation looking at incorporating hydrogen into the natural gas infrastructure.

In response to this feedback, we have made the following adjustments to our model input data.

	Solar WACC[30]	Geothermal capital cost reduction	Geothermal carbon cost reduction	Green peakers maximum	Green peakers available after	Castle Hill wind farm earliest build date
Global	6%	50%	80%	1500MW	2035	2035
Reference	6%	50%	80%	1500MW	2035	2035
Growth	5%	50%	80%	1500MW	2035	2035
Environmental	5%	50%	80%	1500MW	2030	2035
Disruptive	6%	50%	80%	1500MW	2035	2035

[30] All other technologies have a 7% WACC.

Furthermore, in response to the issue of high regional uncertainty we identified regions in relation to the specific transmission assets under examination. These regions are shown in Figure 18 below. We looked at the regional diversity of the generation expansion scenarios and considered that additional adjustments were required to ensure sufficient diversity. These adjustments were made in all scenarios other than Disruptive and are detailed below:

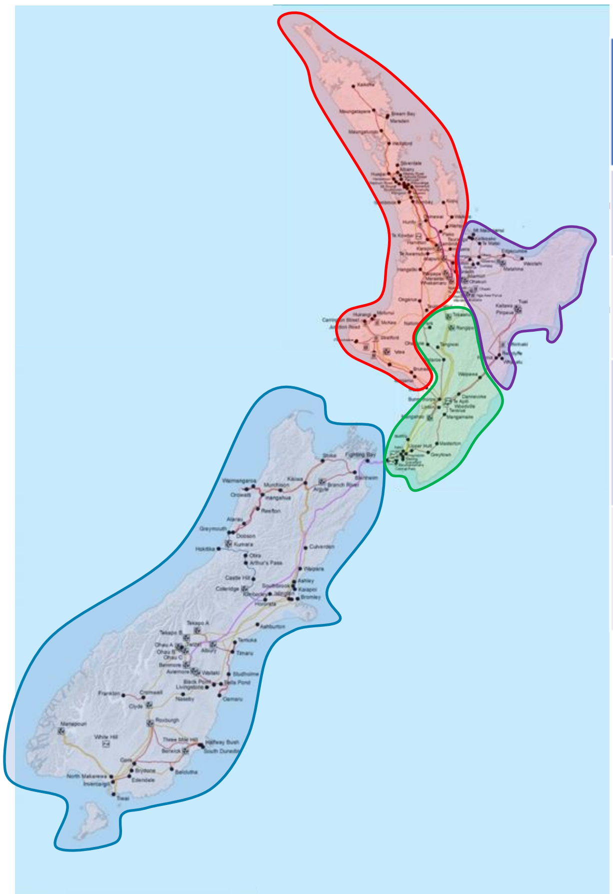
- We added 100MW of solar generation to the Wairakei bus in 2024 and 50MW of wind generation in 2023.
- We subtracted 80MW of solar generation from the Opunake bus in 2024 and 76MW of solar generation in 2024.

1.33 Peaking and dry year solutions

We included a green peaker option within the generation cost stack. This option was defined by a $25/GJ fuel cost with an 11.8GJ/MWh fuel consumption factor and $11.4/MWh variable O&M cost. The peaker was connected to the Huntly bus. This plant provided both a peaking solution and dry year reserve cover in all scenarios other than Disruptive.

In the Disruptive scenario, due to the advanced cost declines of grid scale batteries, the model chose grid scale batteries as the peaking solution. Because the batteries have a maximum of only 4hr storage (at maximum discharge) , the batteries are unable to provide dry year reserve cover. In the disruptive scenario, large scale demand response provides the dry year reserve solution. This demand response is available at the following levels:

First 5% of demand	$600/MWh
Between 5% and 10% of demand	$800/MWh
Between 10% and 15% of demand	$2,000/MWh
Greater than 15% of demand	$10,000/MWh



	Rationale
Region 1	Region 1 contains significant North Island demand centres. Generation expansion within this region is likely to reduce the need for upgrades in the Central North Island, Wairakei ring, and on the HVDC.
Region 2	Region 2 includes the Bay of Plenty, Taupo volcanic zone, and Hawkes bay. Generation expansion within this region is likely to exacerbate the transmission constraint on the Wairakei ring while reducing the need for upgrades in the Central North Island and on the HVDC.
Region 3	Region 3 includes the lower North Island, stretching up to Tokaanu. Generation expansion within this region is likely to primarily exacerbate the transmission constraint in the Central North Island. The Wairakei ring is also exposed to additional flows but to a lesser extent. Generation expansion within this region has potential to reduce the need for upgrades on the HVDC.
Region 4	Region 4 includes the entire South Island. This region has the potential for significant step changes in both load and generation. Any such step change is likely to have an immediate impact on the capacity requirement of the HVDC. Any increase in the net export of this region would also likely exacerbate the transmission constraint in the Central North Island.

Figure 18: Relevant regions for generation scenarios

Appendix B – Stakeholder Consultations

Consultation to date

Early industry engagement

Rio Tinto's announcement to start planning for the wind-down and eventual closure of New Zealand's aluminium smelter at Tiwai Point in the lower South Island presents an opportunity for New Zealand to move toward realising our net zero carbon grid pathway goals.

In September 2020 Transpower introduced our Net Zero Grid Pathways project at an industry webinar.[31] Phase One of this project, which we called Accessing Lower South Island Renewables (ALSIR), comprises Transpower's response to the closure of the Tiwai smelter. This work will help harness the renewable energy currently used by the smelter across New Zealand. It includes the Clutha Upper-Waitaki Lines Project (CUWLP), along with investigations into transmission constraints further north.

To investigate those transmission issues further we went to the industry and established a Scenario Development Panel to assist us develop a view of future electricity demand and supply. The panel sought industry involvement and collaboration to help determine that view.[32]

The Panel explored assumptions, inputs and draft post-smelter demand and generation scenarios relevant to both Phase One and Phase Two of our Net Zero Grid Pathways investigation.

Net Zero Grid Pathways Scenario Consultation

The Scenario Development Panel contributed to our industry scenario consultation in December 2020.[33] In this consultation paper we concluded that demand and generation scenario variations should be determined separately. We had good information to produce reasonable EDGS 2019 demand scenario variations, but not enough information to derive generation scenario variations

In May 2021 we undertook further industry consultation.[34] We targeted potential generation investors, although the consultation was open to all interested persons. Feedback suggested there is too much uncertainty regarding future generation possibilities for grid-connected generation in New Zealand, to reflect in just five nationally determined scenarios, such as the EDGS 2019.

Long List Consultation

With that feedback in mind, as part of this investigation, in August 2021 we published our Long-list consultation document entitled *Net Zero Grid Pathways 1 Long List Consultation.*[35]

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31 Industry webinar, September 2020
32 Establishment of Scenario Development Panel, October 2020
33 Scenario Development: EDGS 2019 Variations Consultation, December 2020
34 Consultation to prioritise generation scenarios, May 2021
35 Net Zero Grid Pathways 1 Long-list consultation and non-transmission solution require for information, August 2021

This consultation document sought feedback from interested parties on our assessment of the need, our initial long-list of components (especially with regard to non-transmission solutions), and any specific non-transmission solutions and the assumptions that we planned to use to identify a preferred solution. This consultation also included an invitation for information on non-transmission solutions.

We also described a possible approach to developing scenarios suitable for NZGP1. That approach reflected the considerable uncertainty in regard to where new generation will be built, but was complex and necessarily involved significant judgement.

NZGP1 Scenario Update

In December 2021 we published our view of future electricity supply and demand scenarios for NZGP1.[36] The paper noted that, based on feedback, we had decided it would be both difficult to apply, potentially contentious, and may be difficult to demonstrate to the Commerce Commission that the resultant scenarios are reasonable variations of the EDGS.

Therefore, in this paper we changed our approach and the scenarios we proposed for the NZGP1 investigation were aligned with EDGS 2019. We confirmed we would be using the same five scenarios as in EDGS 2019, but with updated inputs and the differences between scenarios is very similar to the EDGS 2019. We have named our scenarios NZGP1 scenarios. Not all of the uncertainty identified in reviewing the EDGS 2019 is reflected in our NZGP1 scenarios, so we will also consider both sensitivities and some sensitivity scenarios in our MCP. Sensitivities play an important role in assessing the outcomes from the scenarios and inform the robustness of the proposed investment.

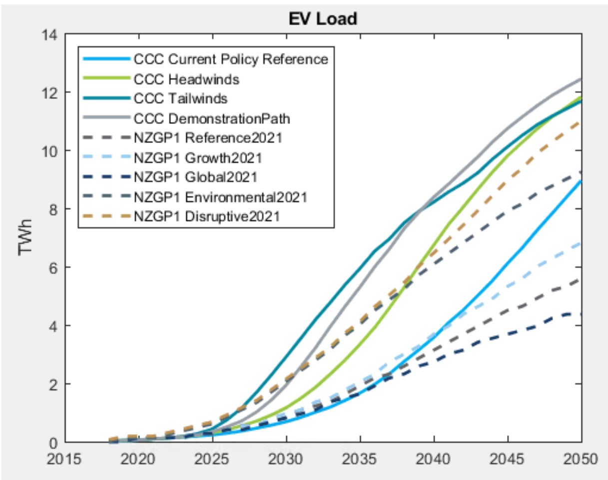
[36] NZGP1 Scenario Update, December 2021

How we addressed issues raised in submissions

The Capex IM requires us to address any submissions raised in respect of each option described during the previous consultation. That consultation was the NZGP Scenarios and Long-list consultation. The submissions received are available here .

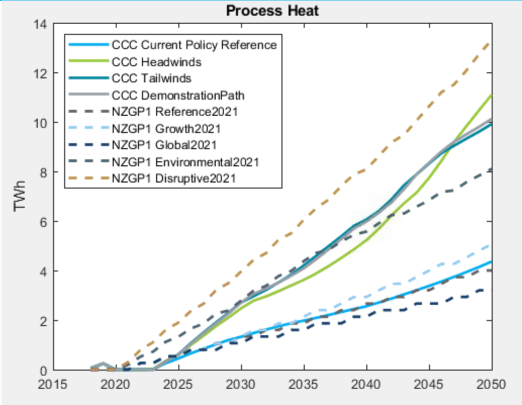
Submissions raised a number of points in the feedback and we undertook to take action in response to submission feedback received. These points and how we have addressed them are itemised in 34, with the middle column providing a reference to which consultation the feedback was raised.

Table 35: How we addressed submissions' feedback

Feedback	§	Comment
Mercury noted that because of the dynamic environment and potential future announcements scenario assumptions should be updated to reflect any significant announcements where the amendments to scenarios would be non-controversial. E.g., assumptions should now assume longer dated operations for the smelter. Transpower should continue to consult on issues which are more material or for which Transpower must make judgement decisions.	Scenario	We have tried to ensure our assumptions encompass future possibilities, but our Investment Test analysis reflects known information only, e.g., Tiwai Aluminium Smelter only has a supply contract until the end of 2024, so that is reflected in all scenario variations. We have sensitised our Investment Test analysis to that particular assumption. We attempt to accommodate the most recent publicly available information into our scenarios.
Mercury noted that the government's decarbonisation plans to electrify and the Climate Change Commission's draft advice, if accepted and acted on by the Government, is likely to result in an even higher proportion of transport electrification by 2050. This will likely add to the demand assumptions under all scenarios.	Scenario	Thank you for your comments. Our EV load scenarios were guided by an expert panel and were supported by the majority of the scenario consultation feedback. EV load from the CCC and our NZGP1 scenarios are shown in the following chart. 

<table>
<tr><th>Feedback</th><th>§</th><th>Comment</th></tr>
<tr><td></td><td></td><td>While our scenarios are similar to those of the Climate Change Commission advice at 2050, there are a few scenarios where EV take up sits a little lower. Despite this, forecasting is difficult and we believe that our scenarios do encapsulate a range of potential energy futures.</td></tr>
<tr><td>Mercury and Trustpower did not agree with the assumptions made for gas prices. They do not expect it would be reasonable to assume a flat gas price of $6.19/GJ to 2050. They would expect the price of gas to increase in line with carbon prices in line with the Climate Change Commission’s carbon price path.</td><td>Scenario</td><td>We agree. Our gas price assumptions are now consistent with the Climate Change Commission’s gas price as reflected in their “All other CCC scenarios” assumption, as shown in the table below:
<table><tr><th></th><th>2030</th><th>2040</th><th>2050</th></tr><tr><td>Gas price, $/GJ</td><td>6.65</td><td>6.89</td><td>7.84</td></tr></table></td></tr>
<tr><td>Mercury stated that they were not sure if Lake Onslow should be explicitly included in the scenarios. The NZ Battery project may ultimately recommend a solution or set of solutions to the “dry year” problem that differ from the specific solution that Lake Onslow represents and therefore Transpower’s approach should attempt to reflect this. Trustpower and Unison echoed similar concerns given Onslow’s technical, cost and political risks.</td><td>Scenario</td><td>We have not modelled Lake Onslow in any of our five EDGS variations. Instead, we have considered a Lake Onslow sensitivity through our North Island mixed dry year reserve approach. This is described more fully on page 38 of our December 2021 document.</td></tr>
<tr><td>Unison suggested that scenarios should consider a future with high EV uptake and charging behaviour with low demand response where consumers value availability of mobility over reduced costs from flexibility in charging.</td><td>Scenario</td><td>The result of such behaviour would be to increase demand at peak times of the day and the cost to meet such demand would likely be high. We have assumed that, over time, incentives will be developed to discourage such behaviour, given the likely cost.

We also consider that technology and other variables (such as higher tariffs for faster charging) would temper adverse network impacts. Battery capacity is also improving such that a single charge on later model EVs provides sufficient range for charging to not be required every day.</td></tr>
<tr><td>In relation to the Climate Change Commission’s report Transpower’s process heat electrification demand variation projections seem conservative. (Anonymous)</td><td>Scenario</td><td>We have reviewed process heat electrification in our scenarios and these are consistent with the Climate Change Commission advice. The Process Heat electrification from the CCC and our NZGP1 scenarios are shown in the following chart.</td></tr>
</table>

Feedback	§	Comment
		
Consideration should be given as hydrogen as a process input separated from hydrogen as a electricity storage medium. Using produced hydrogen in a fuel cell or combustion unit to produce more energy seems much less efficient than simply using demand response hydrogen plants. Demand response hydrogen should be considered separately than a "hydrogen battery". (Anonymous)	Scenario	The future of hydrogen as a process input, or as a transport fuel, is one of the uncertainties in how New Zealand will decarbonise its energy use in the future. For our planning, our scenarios cover a range of electrification futures, from low electrification to high electrification. Although we don't explicitly mention hydrogen, its role in the future is implicitly varied.
As Transpower is not in the generation business, MEUG and Trustpower raised concerns that subjective views of generation projects identified in the scenarios could become a self-fulfilling prophecy. Both parties would prefer the supply stack to be based on objective data as far as possible and to leave consideration of subjective views of generation projects to be tested with sensitivities.	Scenario	Our EDGS scenario variations are based on MBIE's generation stack, which in turn is based on independent expert advice. Realising uncertainty around issues (such as the relative cost of grid-scale wind and solar generation), we have tested the importance of using the generation stack in relevant scenario sensitivities. However, as suggested, these are sensitivities only.
Meridian notes the potential of flexible hydrogen production to manage dry year risk should also be acknowledged in the sensitivity scenarios.	Scenario	How dry year risk will be managed in the future is an important issue for the transmission grid. This risk will need to be resolved to achieve 100% renewable generation, but it is too early to form a view on the likely options. Our EDGS variations are based on a generic North Island solution (which is least distortionary to our analysis). We have also considered sensitivities (such as a Lake Onslow (South Island) solution), which demonstrates the sensitivity of the future transmission grid to that assumption.

Feedback	§	Comment
		We have not specifically included a flexible hydrogen sensitivity, because it is just one of many alternatives. It is also not clear where or how big the flexible hydrogen plant would be.
Mercury submitted that new generation (e.g., solar) and load development (e.g., electric boilers) can be deployed much faster than transmission enhancements. Vector and Mercury recognises the needs to start planning for major transmission infrastructure in due time, however, the process should ensure flexibility and optionality is maintained so a project can be amended, upgraded or cancelled as required. (i.e., projects that maintain optionality should be preferred).	Long-list	We agree and note that the other important side of that discussion is the role of transmission as an enabler. Building, or having plans to build, transmission is important to generation investors to provide them confidence the transmission infrastructure they require will be in place both where and when they need it. The best outcome for electricity consumers will balance both needs.
Contracting demand side services from distributors (e.g., hot water load control) should also be considered in options to enhancing capacity of the CNI 220kV.	Long-list	The use of demand response is considered a non-transmission solution (NTS) which are important considerations in considering options to address a need. We released a RFI for NTS solutions as part of our August 2021 Long-list consultation. At this stage we have not considered the role that NTS might play as an alternative to enhancing transmission capacity. We note that the use of NTS as an alternative to investment on the backbone grid is unlikely to be economic; but may instead play an important role in enabling the outages required for delivering identified transmission enhancements. We will test the availability and likely cost of NTS alternatives before submitting any investment proposal to the Commerce Commission.
Meridian submit that they are not convinced a battery option would provide long-term transmission requirements to support renewable developments and the broader needs of the CNI investigation.	Long-list	Noted.
Vector raised that the interaction with the TPM and its beneficiaries pay approach should be further considered for this investigation. The needs statements in the consultation document are focused	Long-list	Our analysis and decision-making framework considers costs and benefits to electricity consumers on a national basis. This shortlist of options consultation is accompanied by an indicative benefit-based allocation of costs, showing

Feedback	§	Comment
on supporting generators and that reinforcement far away from demand centres will attract generators to these locations. The process does not take into account the cost to beneficiaries nor that beneficiaries are not provided a choice to incur these costs.		which Transpower customers would be expected to pay and what their proportion of costs is. One aspect of our transmission investment regime that the new TPM is looking to improve is the engagement by interested parties in our decision-making process. Through the publication of indicative transmission cost allocations, it is hoped that identified parties will be incentivised to participate more in the process. E.g., through the proposition of alternatives we may not have considered.
Unison noted that options that accelerate grid access to renewables uptake should be valued in the favoured in the CBA analysis.	Long-list	Our analysis and decision-making framework considers costs and benefits to electricity consumers on a national basis. We consider that this project to be enabling renewables and any investment resulting from this investigation would support renewable uptake.
In order to achieve the 'Net Zero' target, the NZ Geothermal Association also favours options that promote low emissions and these should be included in the criterion for reducing to a shortlist.	Long-list	Our EDGS scenario variations include geothermal generation. Our analysis and decision-making framework considers costs and benefits to electricity consumers on a national basis. We consider that this project to be enabling renewables and any investment resulting from this investigation would support renewable uptake.
Unison noted that options that promote the architecture and enablement of DER uptake should be valued in the CBA methodologies.	Long-list	We consider that DER will have an important role in the future electricity future on New Zealand. Some DER technologies (such as solar PV and batteries) are specifically included in our scenarios. As DER uptake has an impact on the demands of the transmission system we are implicitly valuing these different DER futures in our scenario variations through different levels of future demand that needs to be met.
Options that concentrate Transmission in a narrow corridor should be avoided. Unison requests that evaluation criteria should place greater weighting on options that add resilience particularly in the face of natural hazards. E.g., through increased diversity of transmission routes.	Long-list	Resilience of the transmission grid is an important consideration in grid planning. Because the grid spans the entire country, it is exposed to many natural hazards and diversity of transmission routes is one way of minimising risks to electricity security of supply. We agree with Unison's comments and note that, in the Central North Island, exposure to volcanic activity is the most significant natural hazard. Transpower has been working with University of Canterbury, GNS, University of Auckland and Massey University to understand the risks that volcanic activity pose to the national grid. Our understanding of these credible risks has improved greatly from the recent research and efforts in this area. The quantitative information for ashfall and lahar for the high frequency

Feedback	§	Comment
		cone volcanoes (Taranaki, Ruapehu, Tongariro), shows that the network is exposed. We acknowledge that an option within a narrow corridor will have less resilience where that corridor is much more likely to see ashfall or lahars. We are actively considering resilience of options and ways to mitigate the impacts through route choice and other means and our options analysis will reflect that qualitatively.
Unison and Mercury notes the HVDC alleviates existing and projected south-north constraints but does little to enhance access for new renewable or promote DER which are better facilitated by AC solutions.	Long-list	Noted. A point-to-point HVDC solution has not been included on the shortlist of options included in this consultation.
NZ Geothermal Association submits that growth in geothermal generation should be integral to all generation scenarios, rather than simply giving it prominence in 2 of 15 scenarios. Geothermal is a fundamental building blocks of our low carbon New Zealand electricity generation.	Long-list	There are only five EDGS scenario variations. All scenarios use the same generation stack which includes geothermal generation. The generation expansion model takes the stack and decides what and when generation to build in each scenario variation.
NZ Geothermal Association requests that Transpower mitigate the impacts of decisions on iwi and Māori, employees, employers, regions, and wider communities in the Investment Test Analysis.	Long-list	Transpower is has a focus on mitigating the impacts of its investment decisions on local communities and iwi. For example, Transpower's CommunityCare Fund has been assisting communities affected by our overhead assets (typically transmission lines and towers) by investing in community-based projects that add real value and benefit to those wider communities since 2008. The Fund makes one-off grants to community-based projects near the National Grid.[37]
Mercury supports a holistic approach being taken to ensure that the impacts on all other areas of the grid are captured. For instance, the HAY to BPE corridor should be included as part of the assessment. Increased north flow from the HVDC (as per the long list options and scenarios) and the potential for new regional	Long-list	We agree. We continue to monitor the impacts of potential investments and forecast demand/generation changes on the wider transmission network.

[37] https://www.transpower.co.nz/about-us/helping-our-communities/communitycare-fund

Feedback	§	Comment
generation development is likely to put stress on this part of the grid.		
Mercury would like to highlight the possible lack of consideration given to the 110 kV system. From previous experience, the industry has seen that the potential benefits of major work on the 220 kV network can be handicapped by the issues on 110 kV network.	Long-list	We agree. We monitor what is occurring across the entire transmission network and where there are future constraints we model these in our analysis.
Smart Wires proposed the use of modular power flow control (MPFC) to assist in achieving the network balancing and relief of thermal line constraints described within the long-list consultation paper.	Long-list	Thank you for submitting this information. We have passed on this information to the appropriate teams for consideration.
Taheke 8C's submission notes that the use of transmission corridors through Māori land should be the last option for lines upgrades and projects. In addition, any of Taheke's land (or Māori land in general) that is no longer needed for transmission services should be returned to mana whenua.	Long-list	Transpower's project work involves significant engagement with interested stakeholders including mana whenua. We will continue to engage with impacted parties as this investigation/project progresses. When land acquired for transmission purposes is no longer required Transpower meets its obligations under the Public Works Act 1981.

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