Net Zero Grid Pathways 1

Major Capex Proposal (Staged)

Addendum – Amending our proposal

13 June 2023

Contents

1.1 Introduction

On 2 December 2022, we submitted a (staged) major capex proposal (MCP), titled Net Zero Grid Pathways 1 (NZGP1), to the Commerce Commission. This is the first phase of our wider NZGP project which aims to develop a coordinated, New Zealand-wide plan for investment in the interconnected grid and new generation connections to enable a low-carbon, highly electrified future.

Reasons for this addendum – amending our proposal

This addendum replaces the 'Our Proposal' section of our application document and is an amended version of our proposal. We are amending our proposal for following reasons:

Meeting the staging requirements of the Capex IM

NZGP1 is our first application for a staged MCP to provide a net electricity market benefit. Therefore, it is the first time the Capital Expenditure Input Methodology (Capex IM) requirements for staging have been tested for this type of investment. Our NZGP1 MCP originally had three stages. The first, NZGP1.1, was fully explored and developed in our MCP application in December 2022. The second and third stages, NZGP1.2 and NZGP1.3, were outlined as possible future projects, flowing on from NZGP1.1 and further investigations that we proposed to take as part of that first stage. Stage 2 outputs had much greater certainty associated with them.

Following the submission of our application, the Commission informed us that to comply with the Capex IM MCP staging requirements, our preferred investment option must explicitly include all possible investment options that would meet the investment need in possible future stages.

To comply with this requirement, we have amended our proposal in the following ways:

- Preferring Option 11 instead of Option 10. A future investment that is likely to be required to meet the investment need is a rebuild of the Wairakei-Whakamaru A line or a new line. We included the possibility of one of these project outputs in the second stage of NZGP1 (NZGP1.2). However, we did not model these project outputs in the option we put forward as our preferred option in our proposal on 2 December 2022 (Option 10). Option 10 only included a project output to *investigate* the need for a replacement or new line. Option 11 is identical to Option 10 except that it does include a line rebuild option. This change allows us to investigate and propose solutions to capacity constraints in the Wairakei Ring as part of Stage 2 of NZGP.
- Removal of NZGP1.3 (the third proposed stage of NZGP1). In our discussions with the Commission, it was identified that a future stage project output must be included in our preferred option. Our preferred option does not include an upgraded/ new Central North Island (CNI) line as this did not contribute to a net beneficial outcome. We have also removed the associated project outputs for North Island voltage and stability. We had proposed undertaking several investigations as part of Stage 1 to better determine the benefits and costs if we were to proceed with these projects as part of a Stage 3. We are also required to remove these preparatory costs ($5.4m) from Stage 1.[1] We intend to include these preparatory costs in our RCP4 proposal.

HVDC Stage 1 timing

Since we started investigating this MCP in early 2021, the likelihood of a Tiwai smelter exit in 2024 has changed.

[1] While we have excluded the new CNI line from a possible future stage of this MCP, based on the specific requirements of the Capex IM, we will still assess the need for a new CNI line as part of NZGP Phase 2.

We consider that there are substantial benefits from undertaking our proposed HVDC Stage 1 works at the timing included in our proposal, even if the Tiwai smelter exit is deferred. We are carrying out analysis to quantify the redundancy benefits of the HVDC Stage 1 investment and will provide the results of this work as part of our submission to the Commission's consultation. (This will allow the analysis to be available for cross-submissions.)

However, in order to facilitate an approval of the MCP, Transpower propose to make the HVDC Stage 1 works a 'contingent' project output.[2] This means we will not commence the procurement, design, and build of the HVDC Stage 1 investment until we can quantitatively demonstrate, to the Commission, positive net benefits associated with the investment. The trigger for this could be confirmation of Tiwai's departure date, modelling to show the additional redundancy benefits from the STATCOM, or more certainty in the generation mix or load forecasts.

We consider that our proposed changes to our MCP are not a material change because:

- there is no change to the options we consulted on, and therefore no impact on the cost benefit analysis that stakeholders reviewed; and
- aside from the removal of the preparatory costs it does not change any of the material Stage 1 project outputs or costs, or the Stage 2 project outputs.

[2] This is not a defined term in the Capex IM, however Transpower is willing to commit to a contingency arrangement.

1.2 Our amended proposal – NZGP1

This MCP is the result of an investigation into three areas of the grid backbone:

- Inter-island HVDC capacity
- CNI 220 kV capacity between Bunnythorpe and Whakamaru
- Wairakei Ring capacity

These are the areas that are most likely to constrain prior to 2035. Our investigations and modelling indicate that the highest net benefits arise from alleviating constraints across all three regions.

The **investment need** for this MCP is to:

enable the efficient dispatch of new generation and a reliable supply for future demand growth over the interconnected grid

For the avoidance of doubt, this does not necessarily mean that our options include a technically feasible solution to alleviate all constraints as this may not be economic.

1.2.1 Proposal at a glance

To meet the investment need, we have identified a set of least regrets investments that are net beneficial under a range of generation and demand scenarios.[3]

It is important to note that in developing a project of this type, we apply the investment test to 'development plans'; these each consist of a set of investments that together meet the investment need. We do not separately model or assess the net benefits of individual components of a development plan.[4]

We have proposed a two stage MCP to meet the investment need set out above. This proposal seeks funding approval for:

1. shorter term initiatives and investigations on further longer-term issues (Stage 1); and
2. planning and carrying out larger investments (Stage 2).

This allows the Commission, and Transpower, to progress work, and manage future uncertainties. We can deliver project outputs that have clear net benefits while also carrying out relatively low-cost preparatory work to determine whether future stages are required and, if they are, what the optimal solutions are. This application seeks funding for Stage 1 of NZGP1, which we refer to as NZGP1.1.

Approval for Stage 2 investments will be sought when the need, scope, and cost of those investments is more certain.

The total cost of NZGP1.1 is expected to be $320.6 million. The major capex allowance (MCA) we are applying for is $386.8 million.

A summary of NZGP1.1 is provided in the table below.

[3] The scenarios used are "reasonable variations" of the Electricity Demand and Generation Scenarios (EDGS), developed through public panel discussion and formal consultation in December 2020.

[4] The Investment test assesses which combination of transmission and generation minimises the total delivered cost of electricity. Different transmission options enable different electricity generation options. The generation build reflected in some transmission options would be constrained in other transmission options. As such, it is not possible to define the need as a specific transmission capacity requirement. This complicates the analysis, but is necessary to ensure the "…efficient dispatch of new generation…" in each scenario.

Table 1: NZGP1.1 at a glance

Outcome	Project output
Increase HVDC Transfer average north flow capability from 1070 MW to closer to 1200 MW[5]	Install new +/-60 MVAr continuous/120 MVAr overload STATCOM, +49MVAr filter bank, bus extension and associated equipment.
Increase transfer capacity north from Bunnythorpe by between 60% and 90%[6]	Install Variable Line Rating (**VLR**) and tactical thermal upgrade (**TTU**) of both 220 kV circuits on the Tokaanu-Whakamaru A and B lines to 95°C
	Duplex the 220 kV Tokaanu-Whakamaru A and B circuits with Goat conductor to operate at a maximum temperature of 120°C
	Install VLR and TTU of the 220 kV Bunnythorpe-Tokaanu A and B circuits to 95°C
	Split the 110 kV Bunnythorpe-Ongarue A circuit at Ongarue
	Upgrade protection on the 220 kV Huntly – Stratford 1 circuit on the Huntly-Taumarunui A line and Stratford-Taumarunui A line, between Huntly and Stratford
	Replace the special protection scheme at Tokaanu
Increase Wairakei Ring transmission capacity by 25% (300 MW) under typical operating conditions[7]	Install a TTU on both circuits of the 220 kV Wairakei-Whakamaru C line to 100°C
	Split the 110kV Edgecumbe-Kawerau circuit
	Install a TTU of the 220 kV Edgecumbe-Kawerau 3 circuit on the Ohakuri-Edgecumbe A and Kawerau-Deviation A lines between Edgecumbe and Kawerau to 90°C
Prepare for investment into Stage two projects	Investigate options for reconductoring either 220 kV Brunswick-Stratford line
	Investigate options, routes and progress designs for a new or enhanced Wairakei-Whakamaru line
When: Commence work as soon as funding is approved. Commissioning date assumption for last Stage 1 investment: 30 June 2028.	
Cost: Major capex allowance: $386.8 million.	
Incentive elements: Major capex incentive rate: **15%** Exempt major capex: None	
Approval expiry: 31 December 2035	

1.2.2 Grid outcomes

This MCP covers investment in projects with specific physical outputs. We are seeking approval for investments that will release more capacity from the existing grid. These improvements can typically

[5] The 1070 MW transfer capability referred to here is the historical average availability of the HVDC link and associated AC assets. This actual transfer capability varies with factors such as the load in Wellington. With the proposed HVDC Stage 1 investments, this will increase to close to 1200 MW.

[6] It is not possible to provide a precise figure for the capacity increase for assets on the interconnected grid. In particular, the level of the capacity increase will depend on the magnitude and direction of flows between Taranaki, the lower North Island, and Wairakei Ring.

[7] It is not possible to provide a precise figure for the capacity increase for assets on the interconnected grid. In particular, the level of the capacity increase will depend on the location of new generation and resulting magnitude and direction of flows.

be deployed within three years of approval. They will deliver immediate market benefits and certainty for new electricity consumers and generation developers.

1.2.2.1 HVDC availability and capacity

Increase HVDC Transfer average north flow capability from 1070 MW to 1200 MW

The role of the HVDC link in Aotearoa New Zealand's electricity system is changing. Originally installed to transfer South Island hydro to the North Island, it is becoming a critical component for security of supply for both the North and South Islands. As thermal generation in the North Island declines, South Island hydro generation becomes more important for the North Island in terms of both energy supply and for firming intermittent generation. This MCP seeks funding to increase the average maximum transfer capability of the existing HVDC link, both northwards and southwards.

The current 'headline' 1200 MW capacity (in unbalanced bipole operation) is often reduced due to regular outages of ancillary equipment and the AC circuits between Haywards and Bunnythorpe. Average north flow capability over the past five years has been 1071 MW.[8] Our proposal includes installation of additional reactive support equipment, which will lift the average north flow capability to close to the 1200 MW north capacity. This equipment comprises a STATCOM, new filter banks, and some associated equipment.

The need and timing for this reactive support investment was originally recognised when it was announced that the Tiwai Point smelter would exit New Zealand. Our initial analysis assumed a 2024 exit date, driving a need to increase north transfer capability as soon as possible. However, since starting work on NZGP1 the likelihood of Tiwai exit in 2024 has changed. Our analysis indicates that there are still net benefits (a combination of quantifiable and unquantifiable) from commissioning the STATCOM (and related equipment) even if Tiwai stays. These benefits (which were not modelled in our December application) include:

- **STATCOM redundancy.** The synchronous condensers at Haywards require frequent maintenance and having any machine out of service for maintenance reduces the HVDC flow limit. We have substantial refurbishment work planned on the existing synchronous condensers over RCP4; installing the new STATCOM by 2027 would assist with providing redundancy for these works in the latter half of the period.
- **Hydrological impacts**. Our modelling has utilised an average of the hydro sequences, but if a wet year occurred prior to the date to which the investment was deferred, this could very quickly offset any deferral benefits. For example, we are currently experiencing a very wet year, but outages on the reactive equipment are restricting the HVDC transfer capacity well below 1200MW.
- **Filter Bank redundancy.** The redundancy benefit of the new filter banks was not included.

We are carrying out analysis to quantify the redundancy benefits of the HVDC Stage 1 investment and will provide the results of this work as part of our submission to the Commission's consultation.

In addition to the above benefits, we also note the following risks from delaying the HVDC elements of this MCP:

---

[8] Note, this measure does not match our annually reported HVDC link availability. The HVDC link includes the HVDC system circuit between Benmore and Haywards comprising the converter stations at Benmore and Haywards and the HVDC transmission circuit between them, carried on HVDC overhead line and undersea cable, connecting the converter stations. This is because the link availability measures exclude other HVDC components and HVAC grid assets.

- **Procurement**. Voltage support equipment is in high demand; supply times are lengthening, and costs increasing above that of inflation. Deferring investment from 2027 will likely increase both costs and delivery timeframes if the STATCOM need is then brought forward.
- **Resourcing**. Proceeding with the 2027 date has benefits in terms of the considerable input required from Transpower staff to integrate the STATCOM into the HVDC controls.

We consider that commissioning the new STATCOM in May 2027 is likely to remain the best option. This would require commitment to the project by end of 2023. However, we are interested in the views of stakeholders on this matter.

In order to progress the approval of this MCP, Transpower propose to make this project output contingent on us demonstrating to the Commission that there are clear net benefits to consumers.

Finally, as demonstrated in our application of the Investment Test, it is also economic to install a fourth Cook Strait cable, increasing the northwards HVDC transfer capacity to 1400 MW. We expect to include the funding request for that investment in our NZGP1.2 MCP.

1.2.2.2 -Central North Island capacity

Increase transfer capacity north from Bunnythorpe by between 60% and 90%

At present, northward flow through the CNI region is close to being constrained at times. Our assets in the CNI are a critical part of the grid, as it connects many regions. The need for investment is highly dependent on the location of new generation development. In general, new generation in the lower North Island (up to Tokaanu) or increased net export from the South Island will exacerbate CNI constraints. For example, we would expect to see constraints if significant new generation were developed south of Bunnythorpe, or the Tiwai Point smelter was shut down.

Our investigation considered options to increase flows through the CNI, under various generation/load futures, ranging from thermal upgrades of existing lines through to building a new line altogether. Based on the modelling results, we believe that investment in additional transmission capacity is necessary to enable generation development in the near term, starting with enhancing existing CNI transmission assets in NZGP1.1.

Our preferred investment options will increase transfer capacity north from Bunnythorpe by 60-90%. The range is because the actual outcomes will vary depending on load in Wellington, and load and generation in Taranaki and the South Island.

1.2.2.3 Wairakei Ring line capacity

Increase Wairakei Ring transmission capacity by 25% (300 MW) under typical operating conditions

Some Wairakei Ring lines are near capacity, and our ability to connect new generation without constraints is limited. New generation in the Bay of Plenty, Taupo volcanic zone and Hawke's Bay (and to a lesser extent, the lower North Island) or a reduction in industrial load in the Bay of Plenty will increase transmission constraints in the Wairakei Ring. In April 2023, we commissioned a device at Atiamuri that will more evenly use these lines. However, our modelling also shows that thermally uprating one of these lines as a part of NZGP1.1 will deliver net benefits. This will increase the electricity flow by a further 25%, or 300 MW, northwards through the Wairakei Ring.

Given the large volume of new generation connections enquiries we are receiving for this region, we consider that this investment should be undertaken as soon as reasonably practicable. Even after this work is completed, we anticipate that we will need to significantly uprate another existing line in the region, or develop a new line altogether. We have included funding in this MCP to carry out studies to identify a suitable new line option. An enhanced A line or new line would be included in NZGP1.2.

1.2.2.4 Preparedness funding

NZGP1.1 includes funding for the investigations described above (preparing for projects in later stages) as 'preparedness'.

This preparedness work allows early planning of additional major grid upgrades, which may be included in an MCP for NZGP1.2. These investigations will enable Transpower to advance its response to large step-changes in generation and demand, should they occur. The anticipated investments for Stage 2, for which we have proposed preparedness funding in Stage 1, are:

- **HVDC** – Fourth HVDC Cook Strait cable - $120m[9]
- **CNI –** Reconductor the 220 kV Brunswick-Stratford A line - $75m
- **Wairakei –** New or enhanced Wairakei-Whakamaru line - $92m[10]

1.2.3 Project timing factors

Planning and installing the large projects in this proposal is complex from a technical, procurement and workforce point of view. The following factors were considered in determining project timings:

- Tiwai closing at the end of 2024 when its current electricity supply contract expires (a prudent assumption, see earlier discussion of this).
- The foreseen difficulties of obtaining outages for delivery of these projects, particularly for the CNI and Wairakei works.
- Our increasing workload across both base work and MCPs means that the efficient use of our workforce will be critical. Flexibility to change workplans at short notice is limited.
- Procurement of equipment. Delivery risks due to supply chain issues are an issue, while lead times for certain equipment (including STATCOMs and sub-sea cables) are increasing.

Providing notice of our intention to deliver these projects at the proposed times will also offer confidence to generation investors and potential users wanting to switch from fossil-fuelled to electricity-based energy.

1.2.4 NZGP1.1 P50 costs, maximum capex allowance, and commissioning

The P50 costs and the Maximum Capex Allowance (MCA) we are seeking approval for are shown in Table 2. The MCA is higher than the P50 because it is calculated by adding Interest During Construction costs and inflation to the P50 cost estimate.

[9] Approximate high-end cost if fourth cable is installed on its own.

[10] Note, while our preferred option only includes one technically feasible (economic) option to meet the investment need, as part of Stage 1 we will investigate a range of technically feasible options including a new D line.

Table 2: Estimated P50, MCA costs ($m), and commissioning of NZGP1.1 projects outputs

Staged project	Purpose	Project outputs	P50	MCA	Estimated commissioning
HVDC	Stage 1	Install reactive plant, filter banks and associated equipment to uprate HVDC transfer capacity	84.4	103.1	2027
		HVDC total[11]	**84.4**	**103.1**	
CNI	Stage 1	Install VLR and TTU 220 kV Tokaanu-Whakamaru A&B circuits	45.5	50.8	2024
CNI	Stage 1	Install duplex conductors on 220 kV Tokaanu-Whakamaru A&B circuits	94.4	119.4	2028
CNI	Stage 1	Install VLR and TTU 220 kV Bunnythorpe-Tokaanu A&B circuits	68.1	83.2	2027
CNI	Stage 1	Install split on 110 kV Bunnythorpe-Ongarue A line at Ongarue	0.5	0.5	2026
CNI	Stage 1	Install upgrades on 220 kV Huntly-Stratford 1 circuit	2.0	2.0	2026
CNI	Stage 1	Replace Special Protection Scheme (SPS) at Tokaanu	1.0	1.0	2026
			211.5	**256.9**	
CNI	Prepare for Stage 2	Investigate options for reconductoring either 220kV Brunswick-Stratford line	2.0	2.0	2025
			2.0	**2.0**	
		CNI total	**213.5**	**258.9**	
Wairakei	Stage 1	Install TTU on 220 kV Wairakei-Whakamaru C circuits	10.6	11.8	2024
Wairakei	Stage 1	Install spilt on 110 kV Edgecumbe-Kawerau circuits	0.0[12]	0.0	2024
Wairakei	Stage 1	Install TTU on 220 kV Edgecumbe-Kawerau 3 circuit	10.1	11.0	2024
			20.7	**22.8**	
Wairakei	Prepare for Stage 2	Investigate options, routes, design new/replace Wairakei- Whakamaru line	2.0	2.0	2026
			2.0	**2.0**	
		Wairakei total	**22.7**	**24.8**	
Total			**320.6**	**386.8**	

[11] A parallel investigation is underway to assess the need to replace the current HVDC cables as they approach the end of their design life. This project incorporates investigation work for stage 2 works on the HVDC so costs have not been included here.

[12] The cost of this project component is expected to be less than $50,000.

Appendix A - Options

Our amended proposal selects Option 11 as the preferred option, rather than Option 10.

We made this change because Option 10 did not include a Stage 2 Wairakei Ring upgrade, whereas Option 11 does. Table A1 shows the projects included in options 10, 11 and 12 – the options with the highest net benefits – for reference. Only the Wairakei Ring project outputs vary across the options.

Table A1: Some short-listed HVDC, CNI and Wairakei Ring options, this includes Stage 1 and Stage 2 project outputs

Short-list option	HVDC upgrade	CNI upgrade	Wairakei Ring upgrade
Option 10	New HAY reactive support 4th Cook Strait cable 1400MW	BPE-ONG split HLY-SFD protect upgrades BRK-SFD enhance VLR and TTU TKU-WKM VLR and TTU BPE-TKU Duplex TKU-WKM Replace SPS at Tokaanu	EDG-KAW split TTU WRK-WKM C line TTU EDG-KAW
Option 11	New HAY reactive support 4th Cook Strait cable 1400MW	BPE-ONG split HLY-SFD protect upgrades BRK-SFD enhance VLR and TTU TKU-WKM VLR and TTU BPE-TKU Duplex TKU-WKM Replace SPS at Tokaanu	EDG-KAW split TTU WRK-WKM C line TTU EDG-KAW Replace WRK-WKM A line
Option 12	New HAY reactive support 4th Cook Strait cable 1400MW	BPE-ONG split HLY-SFD protect upgrades BRK-SFD enhance VLR and TTU TKU-WKM VLR and TTU BPE-TKU Duplex TKU-WKM Replace SPS at Tokaanu	EDG-KAW split TTU EDG-KAW Build a new WRK-WKM D line WRK sub equip

Table A2 shows the expected net benefit of all the options. This was included as Table 11 in our application.

Table A2: Net benefit of shortlist of HVDC and CNI and Wairakei Ring options

Shortlisted option	Expected net benefit, PV, $m
Option 1	-$112
Option 2	-$132
Option 3	-$101
Option 4	-$150
Option 5	-$171
Option 6	-$141
Option 7	-$363
Option 8	-$385
Option 9	-$356
Option 10	$57
Option 11	$32
Option 12	$64
Option 13	$17
Option 14	-$10
Option 15	$20
Option 16	-$186
Option 17	-$215
Option 18	-$187

We note that Option 12, which included a new Wairakei-Whakamaru line, had the highest estimated net electricity market benefit. However, we prefer Option 11 as it includes:

- the Wairakei-Whakamaru C line TTU, which delivers significant short-term benefits; and
- the replacement of the A line, which provides additional unquantified benefits through improved security of supply into Eastern Bay of Plenty.

Option 11 is within 10% of the costs of Option 12.[13]

[13] Capex IM, clause D1(2)(a)

TRANSPOWER

TRANSPOWER.CO.NZ