TRANSPOWER

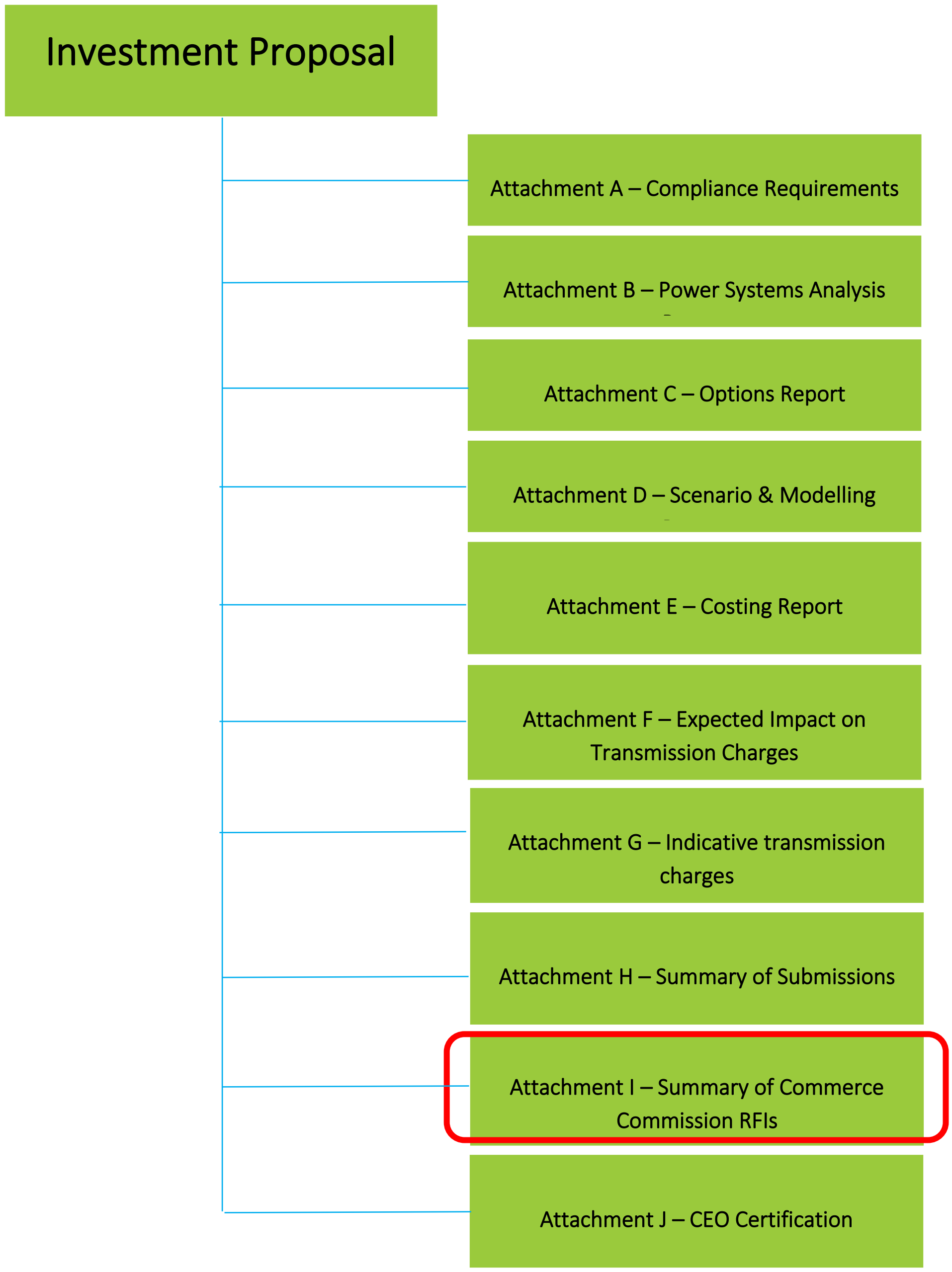
Net Zero Grid Pathways 1

Major Capex Project (Staged) updated

Attachment I: Summary of Commerce Commission RFIs and responses

Date: 25 September 2023

Contents


Investment Proposal
Attachment A – Compliance Requirements
Attachment B – Power Systems Analysis
Attachment C – Options Report
Attachment D – Scenario & Modelling
Attachment E – Costing Report
Attachment F – Expected Impact on Transmission Charges
Attachment G – Indicative transmission charges
Attachment H – Summary of Submissions
Attachment I – Summary of Commerce Commission RFIs
Attachment J – CEO Certification

Introduction

This document is a copy of the Requests for Information (RFIs) from the Commerce Commission to Transpower and Transpower's response to each, as the Commerce Commission's consideration of Transpower's NZGP1.1 MCP progressed.

The Commerce Commission questions are listed in order, followed by Transpower's response.

This is not intended to be an exhaustive copy of all Transpower/Commerce Commission interactions, or even questions and answers.

1.0 RFI001 – received 19/12/2022

1.1.1 Question 1

Please provide the following data for the 2022 calendar

(a) *south to north load flow data via the HVDC link.*
(b) *north flow data at Bunnythorpe for the circuits connecting Bunnythorpe to Central North Island and Bunnythorpe to Taranaki, including the 110 kV circuits.*

The resolution should be sufficient to enable us to develop demand duration curves, which is of similar resolution to what Transpower uses.

The data should be in a format that can be read by excel.

Transpower response

Transpower responded with the requested data on 26 January, 2023.

2.0 RFI002 – received 24/2/2023

2.1.1 Question 1

You have stated in your proposal (page 12) that "NZGP1.1 is to enable the efficient dispatch of new generation and a reliable supply for future demand growth over the interconnected grid"

We are interested in the specific generation projects, and how likely they are, that are driving each of the NZGP1.1 developments, namely:

(a) *What generation project(s) is (are) driving the NZGP1.1 Wairakei Ring investment(s)?*

Transpower response

To answer both this question and (c), which is the same question but for CNI, we have looked at forecast yearly average (across all hydro scenarios) generation for each proposal future project. This was done for both the factual and counterfactual. The factual includes:

- Tiwai leaving in 2024
- A fourth HVDC Cable installed in 2027
- The preferred CNI and Wairakei ring transmission upgrades.

The counterfactual includes Tiwai leaving in 2024 and the existing HVDC and AC grid.

Generation projects have been grouped by the regions shown in Figure 1. We would expect that projects that contribute (as compared to the counterfactual) more generation in Region 3 and 4 will drive investment in the CNI. Projects that contribute more generation in Region 2 and, to a lesser extent, Region 3 will drive investment in the Wairakei ring.

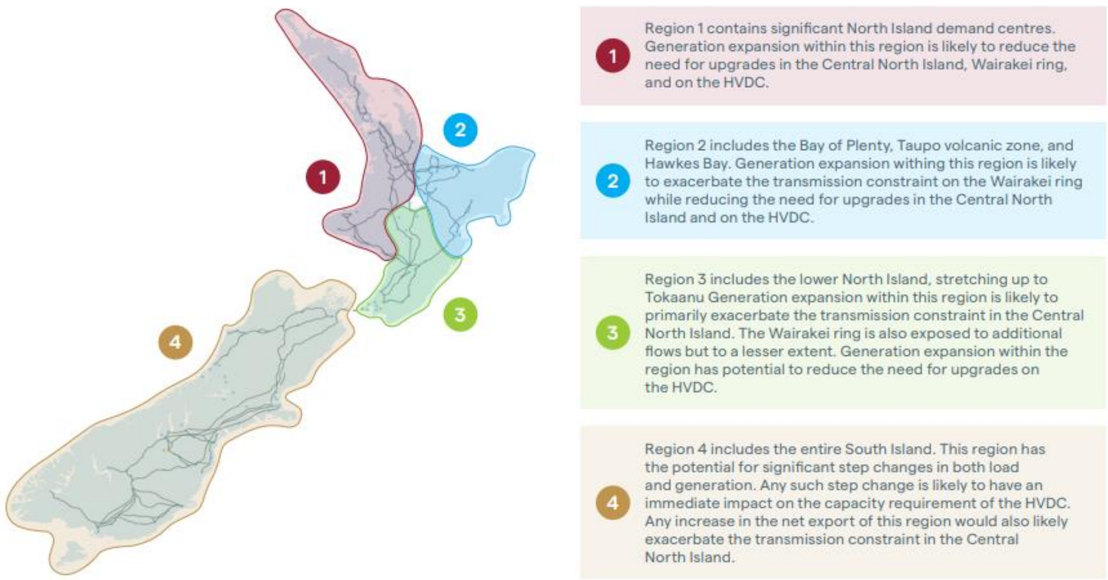


Figure 1 – Transmission regions

Figure 2 shows project generation differences between the factual and counterfactual by region for the Growth scenario. A positive generation difference is where dispatched generation in the factual is greater than dispatched generation in the counterfactual for a given project. We have only shown differences in projects where these are greater than 50 GWh per year (to avoid cluttering the charts). We also provide a spreadsheet with results for the remaining scenarios.

Post 2030 new wind and hydro projects in both Region 3 and 4 contribute to increased generation from these regions compared to the counterfactual. This is similar across most scenarios, although the number of and specific project does vary. After 2040, there is correspondingly less contribution from new generation in Region 1 and 2 compared to the counterfactual.

Changes in generation reflect differences in the factual and counterfactual generation expansion plans. Our factual has more generation built in Region 3 and 4 and less in Region 1 and 2, as compared to the counterfactual.

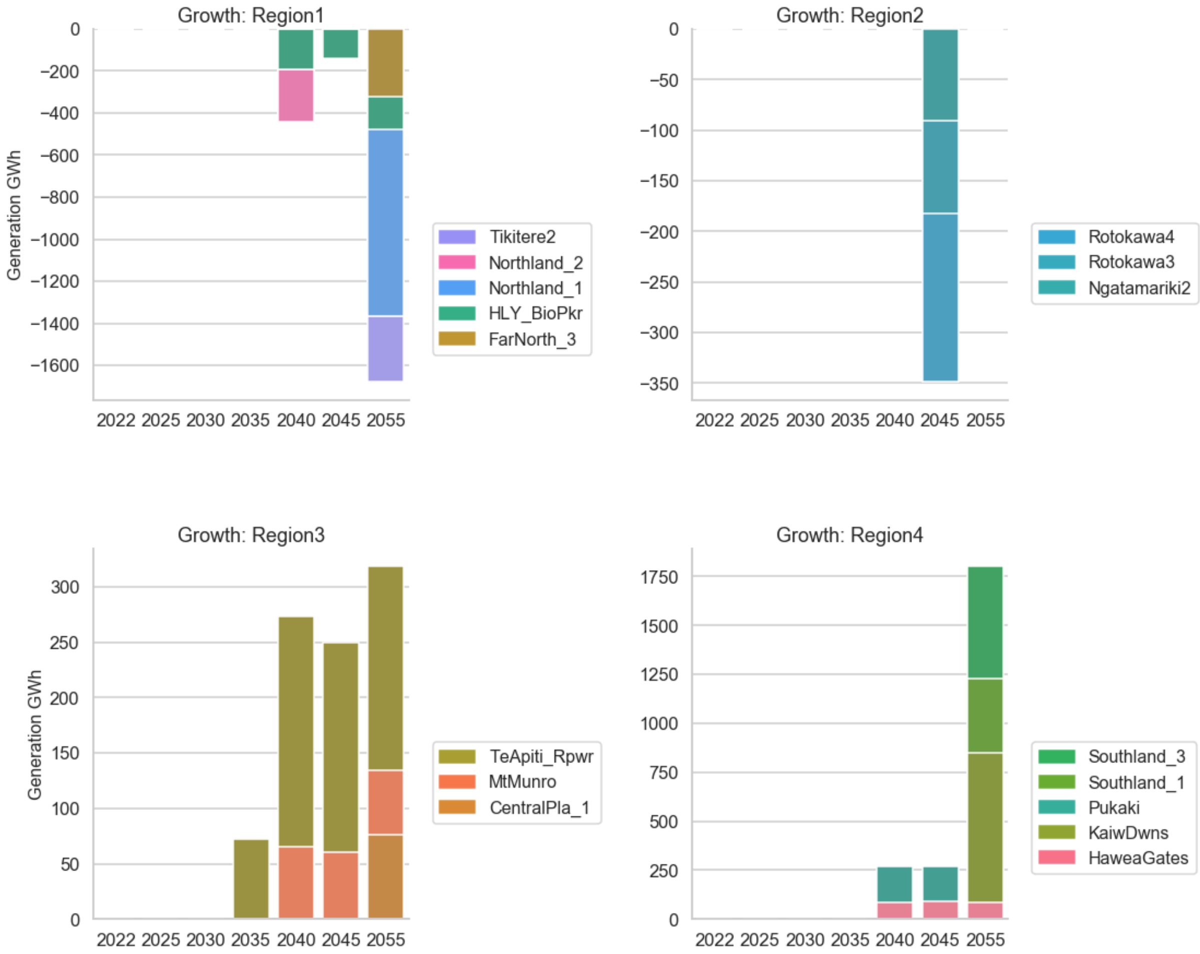


Figure 2 - Factual vs counterfactual generation for new projects, by region, and for the Growth Scenario (only differences greater than 50 GWh shown)

For completeness Figure 3 shows generation differences between the factual and counterfactual for all plant (existing and new) and for the Growth Scenario. This shows increased hydro generation in 2030 for Region 4 (and some other years). South Island (Region 4) hydro generation has increased as greater HVDC capacity allows greater Northwards transfer of this generation when water values (or the opportunity cost of water) are lower than thermal operating costs. Figure 3 shows generation differences compared to the counterfactual for a mean year. Hydro generation differences are likely to be greater for wetter years.

New projects do not by themselves provide the full economic benefits described in our proposal. Other economic benefits are provided by better use of the existing SI hydro generation assets and by reduced transmission losses.

Figure 3: Factual vs counterfactual generation for all (existing and new) generation, by region, and for the Growth Scenario

The data for all scenarios is included in the attached spreadsheet.

2.1.2 Question 2

(b) Prior to NZGP1.1 submission, Transpower provided its Generation Expansion Model spreadsheet to the Commission. We are interested in Transpower's assumptions about certain generation projects, namely Central Wind (150MW assumed to connect at BPE220 by 2024) and Puketoi (300MW assumed to connect at LTN220 by 2024).

> *i. What information does Transpower hold regarding whether the Central Wind and Puketoi projects are progressing past their present consented status? Note that the NZWEA website does not suggest that these projects are, or are planned to be, constructed in the near future. If you hold confidential information about these projects (or any other information being sought in this and other RFIs), then please indicate that this is the case so the appropriate approach to handling that information can be discussed. 2 4608481v2*
>
> *ii. Transpower's Generation Expansion Model suggests that, in all 5 scenarios, 542MW of wind generation is built by 2024 in Regions 2, 3 and 4. What assumption is driving this level*

of generation connection by 2024 and how has Transpower judged that these projects are certain and will proceed in place of new generation connections elsewhere on the grid?

Transpower response

Please note that the version of our generation expansion plans provided to the Commission previously was superseded. A version incorporating the generation expansion plans used to develop our NZGP1.1 proposals has subsequently been provided to the Commission.

In these generation expansion plans neither the Central Wind nor Puketoi projects are built pre 2025 in any scenario. We do not hold any particular information on these projects.

For information, our generation expansion plans assume the following committed generation:

- Turitea wind in 2022 (221 MW)
- Tauhara geothermal 2023 (168 MW)
- Harapaki wind in 2024 (176 MW)
- Ruakaka battery in 2024 (100 MW)
- Te Huka geothermal in 2025 (52 MW)

2.1.3 Question 3

(b) What generation projects are driving each of the CNI investment package increased capacity tranches?

Transpower response

See Transpower response to (a).

2.1.4 Question 4

(d) The proposal indicates that the NZGP1.1 HVDC upgrade investment increase HVDC capacity by approximately 130MW, allowing 1200MW of HVDC north transfer capacity. However, your proposal also suggests that 1200MW of HVDC north transfer capacity is presently available and that the transfer limitation is dependant on other factors, when you state that:

> *"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." (footnote 13 page 30 Main Proposal document)*

and:

> *"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 large*

mechanical rotating machines require frequent maintenance. If any machine is out of service for maintenance, the HVDC north flow limit is reduced." (page 30 Main Proposal document)

Transpower has also stated, on a number of occasions in meetings with Commission staff prior to NZGP1.1 being submitted, and in your stakeholder consultation summary, that the economic justification for the proposed NZGP1.1 HVDC upgrade is independent of Tiwai smelter closure.

i. *We are trying to understand the investment driver and economic justification for the HVDC upgrade component of NZGP1.1. If the economic justification for the NZGP1.1 HVDC upgrade is not dependent on the Tiwai smelter closure, what is justifying this investment?*

ii. *If the economic justification for the NZGP1.1 HVDC upgrade is not driven by the Tiwai smelter closure, can Transpower please provide economic analysis results that demonstrate that the HVDC upgrade component of NZGP1.1 meets the Capex IM investment test? Specifically we are seeking the economic justification for the NZGP1.1 HVDC upgrade and how you have calculated the costs and benefits.*

Transpower has stated in its RCP4 Consultation document that:

"We are planning to perform major refurbishments on the Synchronous condensers over 2025-2030 to ensure units remain operational until 2042" (Table 18, page 66)

iii. *If the economic justification for the NZGP1.1 HVDC upgrade is driven by the increase in HVDC north transfer capacity by avoiding the impact of synchronous condenser maintenance outages, can Transpower supply us with the economic analysis it has carried out that demonstrates that this is the case, and that the HVDC upgrade component of NZGP1.1 meets the Capex IM investment test? Include in your analysis how the proposed synchronous condenser refurbishment in RCP4 will affect HVDC north transfer availability.*

Transpower response

Transpower responded on March 17, 2023, but this was on ongoing conversation and resulted in us including more in-depth analysis in this MCP. See Attachment C, Appendix A.

2.1.5 Question 5

Transpower has stated that it is fielding an unprecedented number of generation enquiries for connection to the grid. How is Transpower prioritising investigations to assess the power system impact of these connections and how does it judge what generation project is more likely, than any other in the country, to proceed?

Note that this question links to Question 1(b)ii but is more generally seeking information on the framework Transpower is employing to judge how potential new generation is more or less likely to proceed, based on known generation costs, connection asset costs, and information Transpower may hold about the intentions of connecting parties.

Transpower response

Subsequent to receiving this question, two online discussions have been undertaken between Rupert Holbrook, our Customer Connections Project Director and Commission staff. Rupert described our new customer connection queueing process and the information available on our website at:

Connection enquiry information | Transpower

Without repeating the content of that website, do Commission staff now have sufficient information to understand our process and answer Question 2?

2.1.6 Question 6

The NZGP1.1 package does not present a New Zealand wide overview of Transpower's net-zero grid pathway work that includes upgrades on the interconnected grid and connections to new generation.

When does Transpower plan to produce coordinated New Zealand-wide NZGP transmission plan that includes analysis of all potential generation developments, their likelihood, and the potential interconnected transmission upgrades and new connections, to access this generation?

Transpower response

We are currently developing a workplan for NZGP2, which will answer this question, excepting we are not currently planning to develop a likelihood for the futures we study.

The timetable for publishing this information is still under discussion, as a part of developing the workplan.

2.1.7 Question 7

We would like to understand the economic impact of the Tiwai smelter exit for a number of exit dates so that we might judge the risk/cost trade-off of surplus South Island generation vs early HVDC capacity uplift. Please provide us with this information for a Tiwai smelter exit by:

(a) 2024 – presumably Transpower could use the analysis presented in Table 16 of the Main Proposal but remove the economic impact of the 4th cable in 2027 from the NPV analysis;

(b) 2027;

(c) 2030; and

(d) 2034 – presumably Transpower could use the analysis presented in Table 16 of the Main Proposal but remove the economic impact of the 4th cable in 2034 from the NPV analysis.

Transpower response

Transpower responded informally to Commission staff on the 3 April 2023. It was agreed no further analysis was required on this subject.

2.1.8 Question 8

Regarding the Tiwai smelter exit, Transpower has assumed this occurs in 2024. Has Transpower carried out analysis of the global aluminium market, the aluminium price forecast over the next 10 years, and how the Rio Tinto plant compares globally, to assess at what electricity price the plant is likely to become uneconomic?

Transpower response

No, we have not undertaken such analysis. It would not be inappropriate for Transpower to use such information to make judgements on the future manufacturing strategy of Rio Tinto, or the future electricity pricing strategy of New Zealand generation companies.

Our role is to ensure there is adequate transmission for operation of a competitive electricity market. The only publicly available knowledge in regard to Tiwai aluminium smelter's future operation is that they only have an electricity supply contract until the end of 2024. This investigation started at a time when previous studies had shown that Manapouri generation could not be fully dispatched into the market unless certain transmission constraints were relieved and that was considered in the NZGP1 investigation.

3.0 RFI003 – received 24/2/2023

3.1.1 Question 1

We are seeking additional information to better understand why it appears Transpower has not considered some alternatives to transmission upgrades in the NZGP1.1 investment package.

Please provide the following information:

We have some general questions about an alternative to grid upgrades to avoid committing capital investment before it may be required.

(a) *Why have N-1 runback arrangements not been considered as technical solutions to accommodate new LNI or Taranaki generation, either as permanent or temporary solutions to relieve N-1 transmission constraints on the BPE to WKM circuits? Transpower regularly* *uses runbacks. We would like to understand why this technical solution has not been considered when it used in other parts of the grid?*

Transpower response

We discussed the role of runbacks in our NZGP1.1 MCP application – please see section 3.5.3 of Attachment C - Options Report. Transpower does regularly use runbacks on lines that form part of spur generation connections into the grid.

The use of generator runbacks to relieve overloading of transmission lines on the core interconnected grid, after the tripping of a line when run above the network N-1 limits, is more challenging and complex. Where core grid lines are operated above their N-1 limit, to ensure the overload on remaining transmission circuits is achieved, if one line trips, requires a wide area special protection scheme. This scheme must act quickly to block and manage the automatic response from other generators as well as the HVDC link, which will otherwise increase their output as a result of the drop in system frequency from the generation runback.

For example, when operating the Tokaanu to Whakamaru section above N-1 with high northwards power transfer if a line tripping occurs, a runback to Tokaanu power station would be required. In addition the system frequency from the runback action will result in increased HVDC transfer into the North Island and free governor response other generating units. This will partially defeat the runback operation to offload the remaining over loaded transmission lines, risking cascade grid failure.

To achieve a robust result and design a runback scheme to cover the likely cases, where operation above the N-1 limit might occur, is necessarily complex and requires the co-operation of a number of generators to achieve a suitable blocking and runback scheme.

Therefore we have not pursued it further.

The HVDC link has the only wide area protection scheme in the power system as part of its control logic. This is to manage a range of operating issues. Its HVDC technology and single path between the two North Island and South Island AC systems makes its control action much simpler than a runback in the core interconnected AC grid. To ensure it is robust has required significant engineering input and a full simulator is used to test and validate operating scenarios.

As noted in section 3.5.3 we are proposing to upgrade the Tokaanu Bus Intertrip, which removes post event overload via grid reconfiguration, not runback. In addition, it is worth noting that we also identified that a tactical upgrade of the Wairakei – Whakamaru C line was a lower cost and more effective option than a runback, for the Wairakei ring section of the transmission network.

4.0 RFI004 – received 24/2/2023

4.1.1 Question 1

We would like to discuss the funding Transpower is seeking for investigations work to:

- *Develop a methodology for quantifying resilience benefits*
- *Investigate lower North Island (LNI) voltage stability*
- *Investigate LNI system stability*
- *Investigate diversifying the Bunnythorpe substation*

(a) Transpower developed a resilience benefit calculation framework that supported substation resilience event mitigation funding in its RCP2 proposal. Why is this resilience benefit calculation framework no longer appropriate? (See Transpower Network Planning reports NP550, NP552, NP572, NP579, NP589, NP591, NP590, NP615, and NP612)

(b) Is it correct that Transpower has already investigated BPE substation diversity in the early 2010s and found that there is only a small diversity benefit accruing there? (See Transpower Network Planning report NP552 June 2012)

(c) Why wouldn't LTN substation provide diversity for BPE substation?

(d) Regarding the funding for investigations to look into lower North Island (LNI) voltage stability, and LNI system stability – Is Transpower carrying out this type of stability analysis work as part of its business-as usual Transmission Planning Report process?

Transpower response

a) Our request for resilience related funding within NZGP1.1 is based on the costs to undertake an assessment of the different line options for the Central North Island upgrade with respect to major hazards.

   We will leverage off the recent report on Volcanic Hazard and Risk Assessment of the Aotearoa NZ Electricity Transmission Network and other information relating to major hazards, where appropriate.

   An assessment of options could use advance modelling such as the MERIT (Measurement of Economic Resilience Infrastructure Tool) or information from our probabilistic service criticality that would be adjusted for the scenario specific restoration times and a modified Value of Lost Load (given a view that VoLL is not applicable for service interruptions greater than 1 day). Any assessment will also consider the level of service expected i.e. what level of resilience and emergency levels of service do our customers expect. The funding request is specifically for the work to undertake this assessment although it may be useful for other NZGP assessments.

Within our Resilience strategy we have signalled the need to develop a resilience decision framework. This funding would not be to develop that framework, but rather would be specific to the new line north of Bunnythorpe analysis and is therefore a different type of study to those referenced by the Commission. Challenges exist with the precision of impacts and likelihood, especially given changes over time such as the new National Seismic Hazard model, and climate change. The uncertainties of likelihood, impact and solution effectiveness suggests a cost effective approach may be more appropriate than an actuarial cost benefit analysis.

b) Yes, however the futures anticipated in NZGP1.1 (and NZGP more generally) were not anticipated at that time. We consider it would be worthwhile updating our view on Bunnythorpe diversity in light of these futures and given the significance of Bunnythorpe within the transmission network.

c) LTN substation may well provide diversity for Bunnythorpe substation, although may require further development for the futures anticipated. That would be one consideration in the proposed study.

d) We do not undertake dynamic voltage/system stability studies as part of our TPR planning – we only report on stability work that we have already carried out for other reasons. Typically dynamic voltage stability investigations are undertaken as a part of MCP investigations – USI and WUNI are two examples.

We do undertake studies into static voltage stability limits as a part of our TPR studies.

The issues we are considering in this NZGP1.1 stability study would largely be driven by the capacity increase coming from NZGP1.1 investments. For this reason, it seems appropriate to fund the dynamic voltage, and in this case, system stability studies as a part of the MCP.

5.0 RFI005 – received 15/3/2023

5.1.1 Question 1

Please provide the generation expansion plan that Transpower used to prepare the major capex proposal for NZGP1.

This data is critical for our evaluation so please ensure that we are sent a verified and correct version.

The data should be in an excel format.

The data fields should include the information shown below as column headings with an example:

Name	Capacity	Technology	EntranceYear	Island	Bus	Region	EDGS Scenario
Turitea	100	Wind	2023	NI	LTN220	3	Disruptive

Note that the capacity of Turitea differs from Transpower's plan because the northern farm (122 MW) was commissioned in December 2021 and I have adjusted the capacity to that of the southern wind farm which is planned to be commissioned in April 2023.

Transpower response

Generation expansion plans that Transpower used to prepare the major capex proposal for NZGP1 are attached to this response as an excel spreadsheet called: "FleetByYearOfEntrance_ComComFormat_As_Sent.xls".

6.0 RFI006 – received 20/3/2023

This RFI seeks further information and clarification on the impact of the proposed major capex project outputs (outputs) on CNI transfer capacity. We understand from Transpower that the relevant information is in Figures 23- 25 of Attachment B of the MCP proposal. The figures in this Attachment are useful since they provide a concise summary of the power system studies that Transpower did. For future applications, it will be useful to us if you could also include a figure showing the transfer capacity achieved by the proposed major capex outputs. With respect to figures 23-25, please advise us the following:

6.1.1 Question 1

Do all limits in Figure 25 assume the Bunnythorpe Ongarue line is split?

Transpower response

n Figure 25, all the limits except for the Basecase limit which is the black dotted line. The Basecase limit is effectively the do-nothing option for comparison purposes.

6.1.2 Question 2

Do all limits assume the HLY-SFD protection limit is removed? Please show constraint set by the HLY-SFD circuit before the protection upgrade.

Transpower response

In Figures 23-25, all the limits assume the protection limit is removed except for the Basecase (the black dotted line in each figure). The Basecase limit is effectively the do-nothing option for comparison purposes.

There are some simulation graphs presented in section 4.1 (Figure 4) of Attachment B. For clarity I have repeated the simulations from Figures 24 and 25 with the HLY-SFD protection limit in place, the graphs are shown in Appendix A of this document.

6.1.3 Question 3

For the Stage 2 line (blue line) in Figure 25, does the constraint refer to both the TKU-WKM and BPETKU being thermally upgraded (TTU) and with VLR? The description does not mention TTU for BPE-TKU.

Transpower response

Yes, both TKU-WKM and BPE-TKU are thermally upgraded (TTU) with VLR.

6.1.4 Question 4

For Stage 3 (green line) in Figure 25, which circuit is the contingency?

Transpower response

BPE-TKU. i.e., the constraint in the graph is overloading a BPE-TKU circuit for contingency of the other BPE-TKU circuit

6.1.5 Question 5

Please provide the line impedances for before and after duplexing TKU-WKM and BPE-TKU circuits so we can estimate the loss benefits.

Transpower response

The parameters before and after duplexing are provided in Appendix B

6.1.6 Question 6

Please advise the expected north transfer capacity after the new line is built. We realise that the new line is not fully specified so also provide the assumptions/parameters of the new line used in the modelling? Grid Planning has advised that the transfer capacity of the new line in the MCP *proposal Attachment B does not reflect the effect of all the major capex outputs that would be delivered by stage 1.*

Transpower response

As per Figure 24 three new line options were considered by System Planning:

- New 220 kV double circuit duplex line between Bunnythorpe–Whakamaru, duplex Sulfur AAAC at 90°C sag
- New 220 kV double circuit duplex line between Bunnythorpe–Woodville–Waipawa–Fernhill– Redclyffe, duplex Sulfur AAAC at 90°C sag
- New 220 kV double circuit duplex line between Bunnythorpe–Stratford–Huntly, duplex Sulfur AAAC at 90°C sag

In Transpower's MCP submission funding was requested to assess the new line option further. This would have included, more detailed study, high level route analysis, resilience assessment and design. The assessment would have helped Transpower choose a preferred line route. Without this analysis System Planning has made an assumption and chosen the Bunnythorpe–Whakamaru new line option to answer this question. It is considered the constraints may change between the new line options and the transfer limits may differ when Bunnythorpe–Tokaanu and Tokaanu–Whakamaru 220 kV circuits are duplexed. Therefore, the transfer limit calculated in this response is indicative.

The analysis is presented in Appendix C.

<u>Appendix A – Question 2</u>

Do all limits assume the HLY-SFD protection limit is removed? Please show constraint set by the HLY-SFD circuit before the protection upgrade.

Transpower Response:

In Figure 1 and Figure 2 the Huntly–Stratford circuit constraints which have developed when the protection limit is removed have been marked with red arrows.

Figure 1 shows a reduction in Bunnythorpe transfer (MW) when the Huntly–Stratford protection limit is in place for all simulations except:

- The orange trend when a new double circuit 220 kV line via Bunnythorpe–Stratford–Huntly is built. This is because the new line is parallel to the existing Huntly-Stratford 220 kV circuit, hence power is shifted off the existing circuit. This delays the Huntly-Stratford 220 kV circuit constraint from binding and limiting Bunnythorpe transfer.
- The black trend, the Basecase simulation. The Basecase1 simulation has the Huntly–Stratford protection limit applied in all graphs.

Figure 2 shows a reduction in Bunnythorpe transfer (MW) when the Huntly–Stratford protection limit is in place for all simulations except:

- The black trend, the Basecase simulation. The Basecase simulation has the Huntly–Stratford protection limit applied in all graphs

Figure 1: Transfer limits without and with Huntly–Stratford protection limit

Left graph without Huntly–Stratford Protection limit, Right graph with Huntly–Stratford Protection limit.

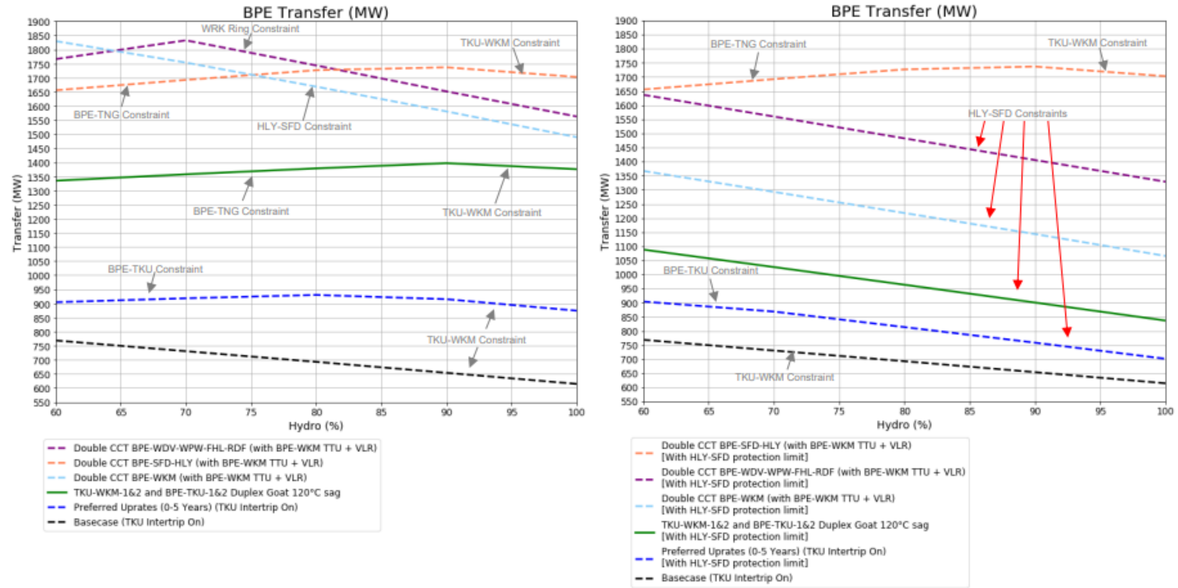
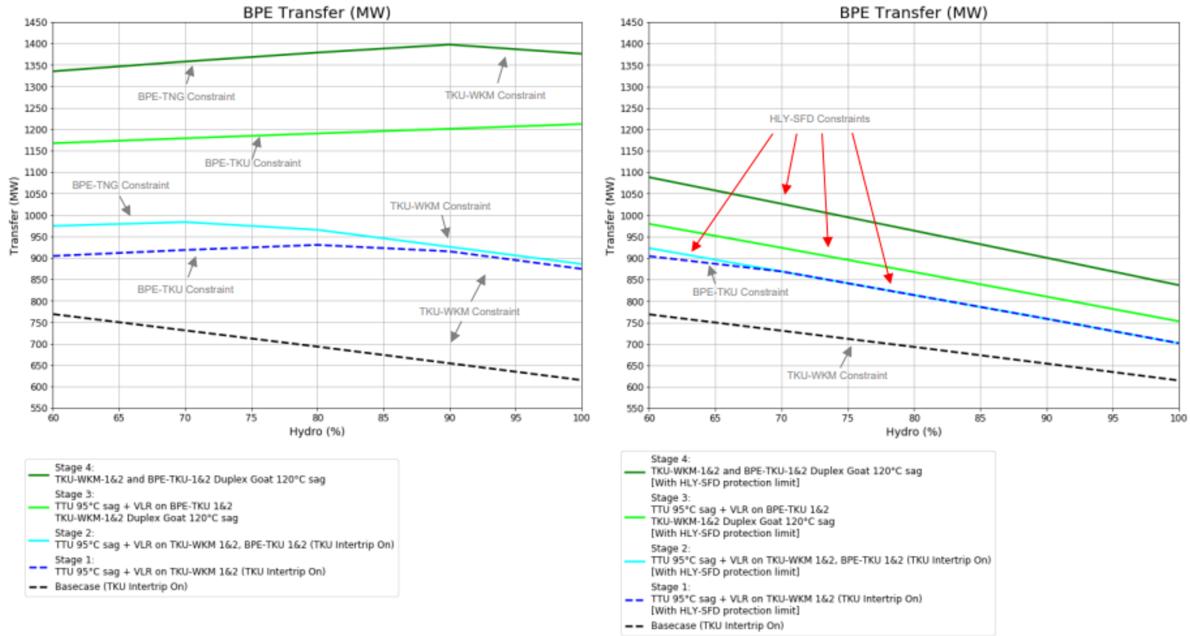


Figure 2: Transfer limits without and with Huntly–Stratford protection limit

Left graph without Huntly–Stratford Protection limit, Right graph with Huntly–Stratford Protection limit.



Appendix B – Question 5

Please provide the line impedances for before and after duplexing TKU-WKM and BPE-TKU circuits so we can estimate the loss benefits.

Transpower response

Transpower Response:

Table 1: Circuit parameters before and after duplexing

Circuit	R	X	Rating (A) - Summer	Rating (A) - Winter
TKU-WKM-1 Existing	6.0416	29.1342	807	880
TKU-WKM-2 Existing	6.0749	29.1134	807	880
TKU-WKM-1 Duplex GoatAC 120°C	2.8008	21.4716	2160	2266
TKU-WKM-2 Duplex GoatAC 120°C	2.8162	21.3558	2160	2266
BPE-TKU-1 Existing	14.4963	69.959	807	880
BPE-TKU-2 Existing	14.4697	69.4824	807	880
BPE-TKU-1 Duplex GoatAC 120°C	6.7194	51.6149	2160	2266
BPE-TKU-2 Duplex GoatAC 120°C	6.7073	50.8629	2160	2266

Appendix C – Question 6

Please advise the expected north transfer capacity after the new line is built. We realise that the new line is not fully specified so also provide the assumptions/parameters of the new line used in the modelling? Grid Planning has advised that the transfer capacity of the new line in the MCP proposal Attachment B does not reflect the effect of all the major capex outputs that would be delivered by stage 1.

Transpower response

The parameters used for the new line between Bunnythorpe and Whakamaru are shown in Table 2. The parameters represent a 220 kV double circuit duplex line with conductor Sulfur AAAC at 90°C sag.

Table 2: Circuit parameters for a new double circuit line between Bunnythorpe and Whakamaru 220 kV substations

Circuit	R	X	Rating (A) - Summer	Rating (A) - Winter
BPE-WKM-1	6.197	82.250	2694	2896
BPE-WKM-2	6.197	82.250	2694	2896

The following scenario has been studied:

- A new 220 kV double circuit duplex line between Bunnythorpe and Whakamaru,
- Tokaanu–Whakamaru 220 kV circuits duplexed with GoatAC 120°C sag temperature.
- Bunnythorpe–Tokaanu 220 kV circuits duplexed with GoatAC 120°C sag temperature.

The transfer limit is shown by the lime green trend in Figure 3 below. The Bunnythorpe–Tangiwai 220 kV circuit limited the transfer at lower hydro dispatch values. To resolve this a TTU was applied to the Bunnythorpe–Tangiwai, Rangipo–Tangiwai and Tangiwai–Wairakei 220 kV circuits. This has been considered by the Transpower lines team, and it is feasible. It's assumed the cost to complete the TTU work would be small compared to the cost required to build a new line and duplex the Bunnythorpe–Tokaanu and Tokaanu–Whakamaru 220 kV circuits. The new transfer limit is shown by the dashed grey trend.

The two new transfer limits (lime green and grey) are approximately 2200-2300 MW and have increased from 1700 MW. Approximately 1700 MW was achieved in previous new line studies2 without duplex reconductoring (the purple, light-blue and orange trends in Figure 3). Table 3 shows indicative capacity values for clarity.

Table 3: Indicative transfer levels[3]

Scenario	Figure 3 Trend	BPE Transfer (MW)
New 220 kV double circuit duplex line between BPE and WKM, TKU-WKM and BPE-TKU duplexed with GoatAC at 120°C sag	Grey dashed line, Lime green solid line	≈ 2200 - 2300
New 220 kV double circuit duplex line between BPE and WKM, BPE-TKU and TKU-WKM both have TTU + VLR	Purple dashed line, Light Blue dashed line, Orange dashed line.	≈ 1700
TKU-WKM and BPE-TKU duplexed with GoatAC at 120°C sag	Dark green solid line	≈ 1350
TKU-WKM TTU + VLR	Dark blue dashed line	≈ 910
Basecase	Black dashed line	≈ 690

2 Information was presented in Figure 24 as part of the CNI study results included in Transpower's MCP submission, December 2022.

3 These transfer levels all have the 110 kV system split at Ongarue applied and the Huntly–Stratford protection limit removed.

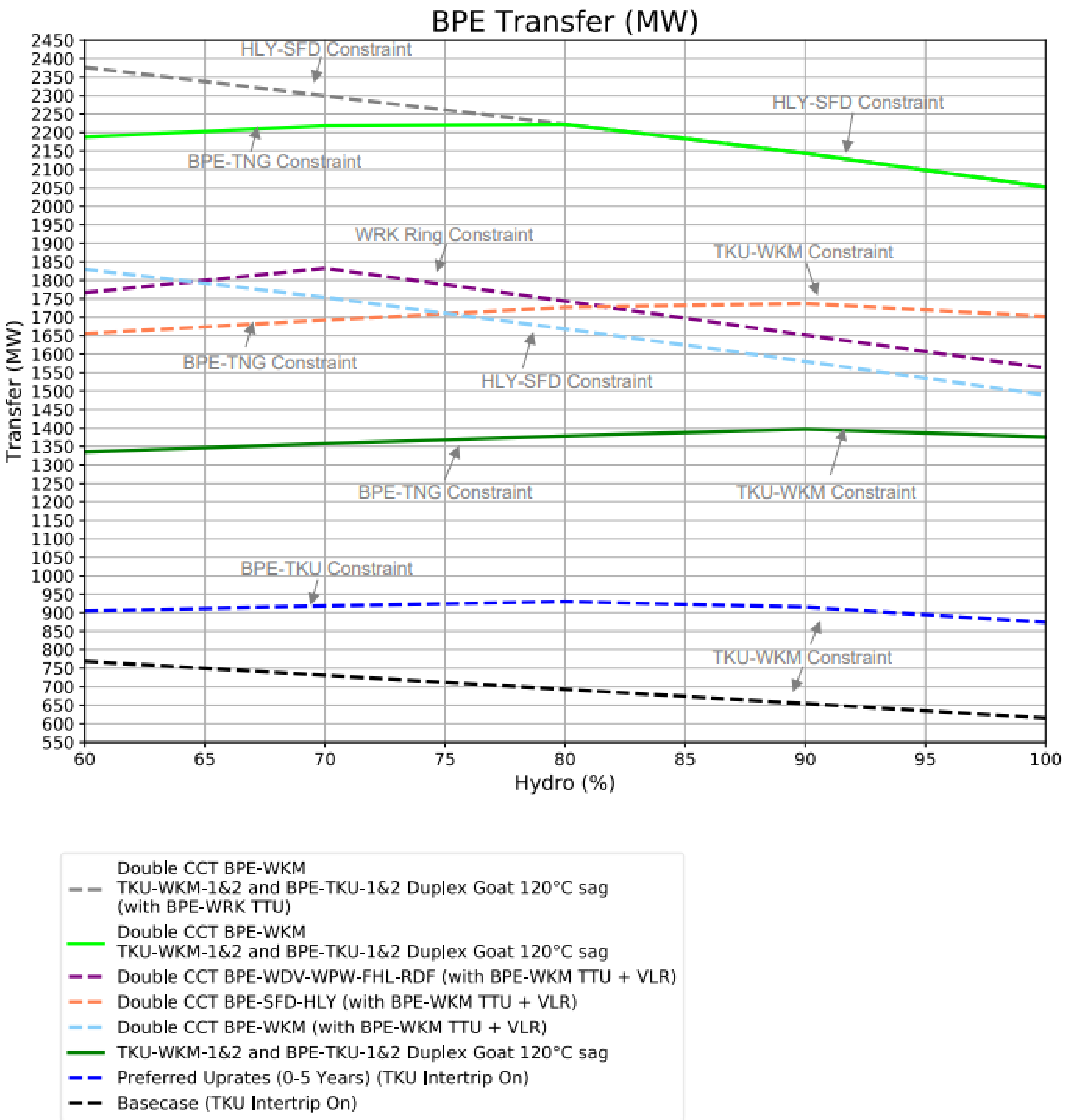


Figure 3: Transfer limit when a new 220 kV double circuit line is built between Bunnythorpe and Whakamaru and the existing Tokaanu–Whakamaru and Bunnythorpe–Tokaanu 220 kV circuits are duplexed.

7.0 RFI007 – received 20/3/2023

7.1.1 Question 1

1. *How did you model South Island load growth – both organic growth and growth due to decarbonisation?*
2. *We are aware that the potential for large demand, due to Hydrogen conversion and data centres, came after you had set up your models. Please advise to what extent you were able to include the impact of these in your studies.*

Transpower response

We have based our analysis on reasonable variations to the Electricity Demand and Generation Scenarios (EDGS) that we developed through public panel discussions and formal consultation in December 2020 as part of our development of our proposal. At a national level we adjusted national base levels of growth down slightly, but significantly increased the amount of process electrification, light electric vehicle uptake, and solar PV uptake to bring them more into line with current expectations (as shown on page 22 of the consultation document). While we feel these changes better reflect current expectations, we have found they tend to cancel each other out, such that overall energy growth rates have remained relatively similar for most of the scenarios. In our revised scenarios South Island energy demand (excluding Tiwai) grows at between 0.7% pa and 1.7% pa over the next 20 years as opposed to 0.4% pa and 1.8% pa in the original EDGS scenarios. Peak demand changes differently though, as a result of process electrification and light electric vehicle uptake.

The potential for new industrial loads to appear after the closure of the Tiwai aluminium smelter, such as new data centres or a new hydrogen production facility, was discussed at the time of finalising the scenarios. At that time, it was decided not to include either a new hydrogen production facility, or data centres, within our base scenarios due to their speculative nature.

Since then, we have seen firmer interest in data centres in Southland and interest in new generation. While these together would offset each other, to some extent, we consider it is more likely that new generation or reduced demand from a Tiwai exit will dominate such that there is an enduring need to export more generation to the North Island. As such we see our proposal as having low regrets.

7.1.2 Question 2

In respect of Deficit costs (or benefits) set out in Transpower's benefit calculation spreadsheet:

a. What do they represent?

Transpower response

Deficit is a parameter used in our modelling. It represents what is more commonly referred to as flexible demand or unserved energy elsewhere in the electricity industry.

Our models build or dispatch available generation to meet electricity demand, with an objective of meeting demand at minimum cost. Meeting demand is a hard constraint, so if that were the only option and there is not enough generation available, the model would become infeasible. Having deficit available avoids the model becoming infeasible, plus it offers the model a choice when looking to minimise cost - deficit has a cost associated with it and the model can decide whether to build new generation (in our generation expansion model), dispatch existing generation, or incur deficit.

In our NZGP1.1 modelling, we used four different tranches of deficit, with four different costs. Three of the tranches represent different levels of flexible demand, ranging from the cheapest (possibly demand response from domestic hot water heating) through to industrial flexible demand. There is a considerable amount of work being undertaken within the industry to establish the processes necessary for flexible demand to participate in the wholesale market and it seems likely such demand will be available in the future. Hence, we have reflected that in our modelling. The fourth tranche of deficit represents unserved energy. It is the highest cost deficit in the model and is rarely incurred. When it is, incurring unserved energy can be thought of as being synonymous with those occasions where actions to ensure the on-going security of the grid may be required.

The unit costs for each tranche of deficit are an important modelling input and we put in a lot of effort to determine appropriate settings. They are similar to expected market costs, but may differ in order to ensure our modelling reflects expected market behaviour. Deficit cost influences how water is stored, for instance. As the unit cost of deficit is increased, the model will tend to store greater volumes of water in reserve for dry periods. In our generation expansion plan modelling the unit cost of deficit influences the timing of new generation with higher unit costs resulting in more generation being built as the consequence of running out of generation is greater.

Figure 1, below, shows deficit cost reductions, by tranche, for Tiwai leaving in 2024, and our proposed upgrades. Most deficit cost reductions are the associated with demand response.

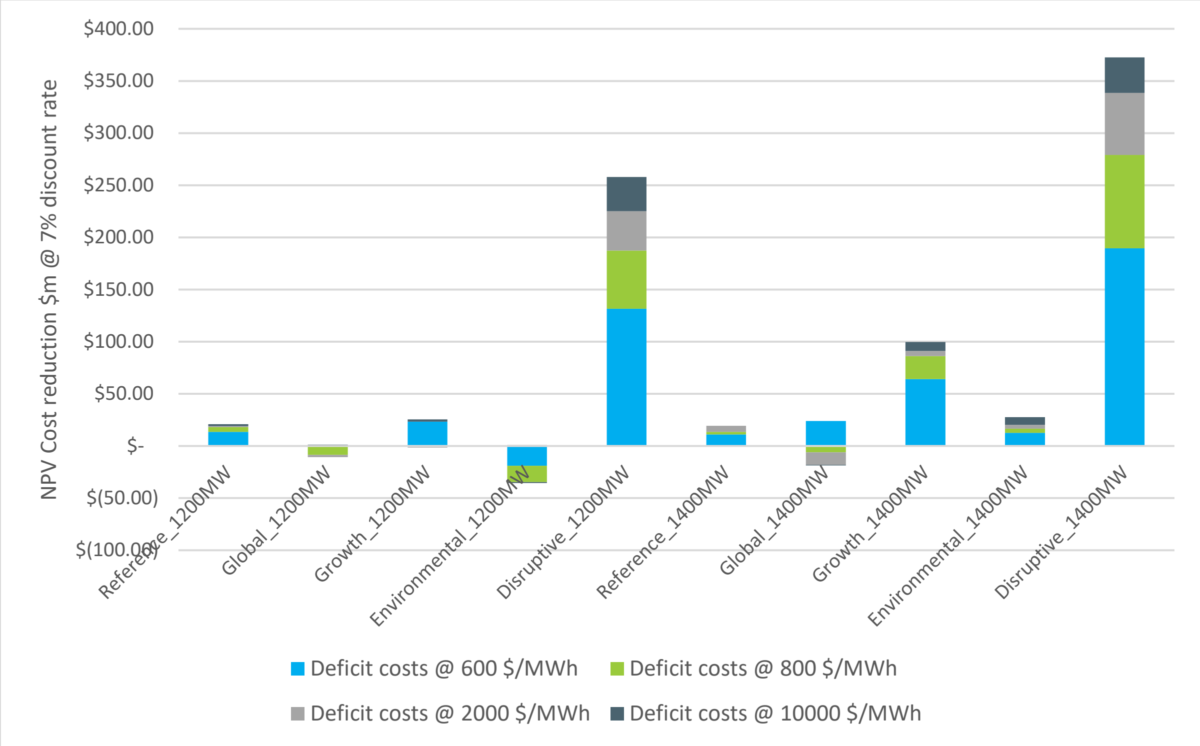


Figure 1: A breakdown of deficit costs by tranche

7.1.3 Question 2

b. *Why does Transpower believe that the Deficit costs result in net market benefits this project?*

Transpower response

Our generation expansion model is a part of PSR Inc's suite of electricity system models and is used throughout the world. The model is required to meet electricity demand, but has the option of doing that by building new generation, dispatching existing generation, using flexible demand, or incurring unserved energy. Its overall objective is to minimise the cost of electricity over the study period. When it builds new generation, the model incurs an annual capital and operating cost. At times it is cheaper to use flexible demand, often as a means of deferring the need for new capital – similar to the evaluations we currently undertake in assessing demand response. Occasionally, it is cheaper to incur unserved energy. For example, this may be the case if the issue only occurs sparsely in an extremely dry year. In such a case the model may determine it is not worth building new generation to mitigate against the issue and instead choose to not supply load.

The benefits of this project are the reduction in electricity costs identified by the generation expansion/dispatch model with the grid enhanced versus not enhanced. We include all costs evaluated by the model, including deficit costs. To not do so would distort the value of the grid enhancement.

7.1.4 Question 3

c. *Why does Transpower consider that forecasting generation expansion that results in deficit in generation is acceptable to the market. This is particularly since the difference between the capital cost of wind generation does not vary significantly by location i.e. wind generation can be built in most locations around the country for similar capital costs. The same applies to solar, a lot of which is being built in the northern half of the north Island (Transpower's regions 1 and 2).*

Transpower response

We do not necessarily expect the market to deliver the outcomes reflected in our modelling, so it is plausible that flexible demand will not prove to be economic compared to building new generation, however our model has identified it to be economic and lower cost than building new generation, in some instances. We could force the model to build new generation instead[1], but that would cost more and in our view overstate the benefits of the transmission enhancement options we considered.

This approach is similar to approach taken by the Electricity Authority (EA) in developing the market security of supply of supply standards. In their 2016 consultation on these standards the EA state:

"Each security of supply standard is intended to represent an optimal level of investment, in the narrow sense that the combined cost of shortage and reserve generation is minimised. In other words, the marginal cost of adding new reserve generation is equal to the marginal benefit of reducing unserved energy. It may be that a higher level of investment is optimal when other considerations are taken into account. "

7.1.5 Question 4

d. *In section 3.2.1 of Attachment D, you mention that all scenarios build a significant quantity of biofuels in the 2030s. Biofuels result in high thermal costs (or benefit elements) after 2035 as shown in Figure 19 (of the MCP application documents – copied below). Please explain why you consider it reasonable to forecast biofuel plants and then include the cost of operating these as benefits provided by the major capex project.*

Transpower response

The Rankine units retire in 2030 in our modelling, so we needed something to provide dry year reserve after that. We are aware that the provision of dry year reserve is very much a live topic of discussion at the moment in the industry. The approach we took was to assume a biofuel plant

[1] We note that although there has been a lot of interest in solar generation in Northland and Waikato (our regions 1 and 2), few projects have reached the committed stage to date. More recently, solar opportunities are being investigated in the mid/lower North Island and South Island. Again, these changes support our low regrets proposal and Stage 2 or 3 projects, which will enable more new generation to be connected in these regions.

could be built at the existing Huntly site and operated just as the existing Rankine units are. In our view this is a non-distortionary approach to evaluating the benefits of the transmission enhancement options we considered. If we had instead, assumed Lake Onslow proceeded, for instance, the outcome would likely have been a profound effect on the need for the HVDC and CNI transmission enhancements considered. A decision to proceed with Lake Onslow is uncertain at the moment, so including such an assumption would not have been reasonable. As we have stated elsewhere, the benefits reflected in our MCP are likely to be understated as we have chosen to use conservative assumptions (not favouring any likely proposal) in our investigation.

7.1.6 Question 5

Figure 19 shows your estimated benefits over time. As seen below, there are little benefits until 2035 and most of the benefits come after 2035.

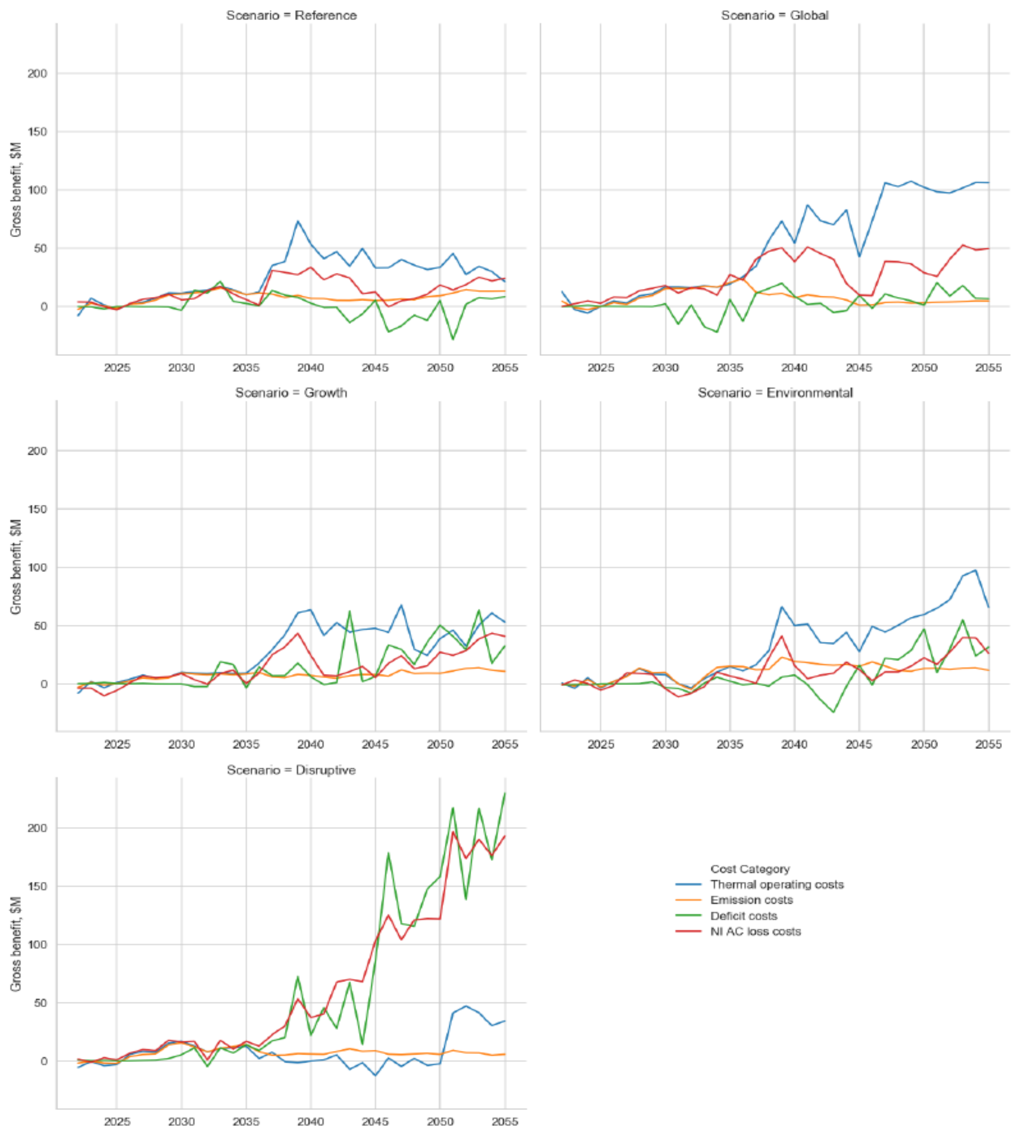


Figure 19: Preferred option gross benefits over time, Tiwai leaves 2024, HVDC fourth cable 2027

Figure 2 – a copy of Figure 19 from the NZGP1.1 MCP proposal

a. *The results in Figure 19 suggest that Tiwai exit is not providing any significant benefit. Otherwise your calculations will show significant benefits from 2024. Please provide us with your annual calculated benefits, if available.*

Transpower response

Annual calculated benefits for Tiwai leaves in 2024 are attached. As with Figure 19, annual benefits are undiscounted.

Figure 3 compares total NPV benefits from 2022 - 2055 and from 2022 – 2035 with Tiwai leaves in 2024, the fourth HVDC cable installed late in 2027 and the preferred AC transmission upgrade option. Total NPV benefits from 2022 to 2035 are not insignificant. The majority of benefits within this time frame occur after the HVDC fourth cable is installed. This is unsurprising given that many of our proposed transmission upgrades are not in place until 2028.

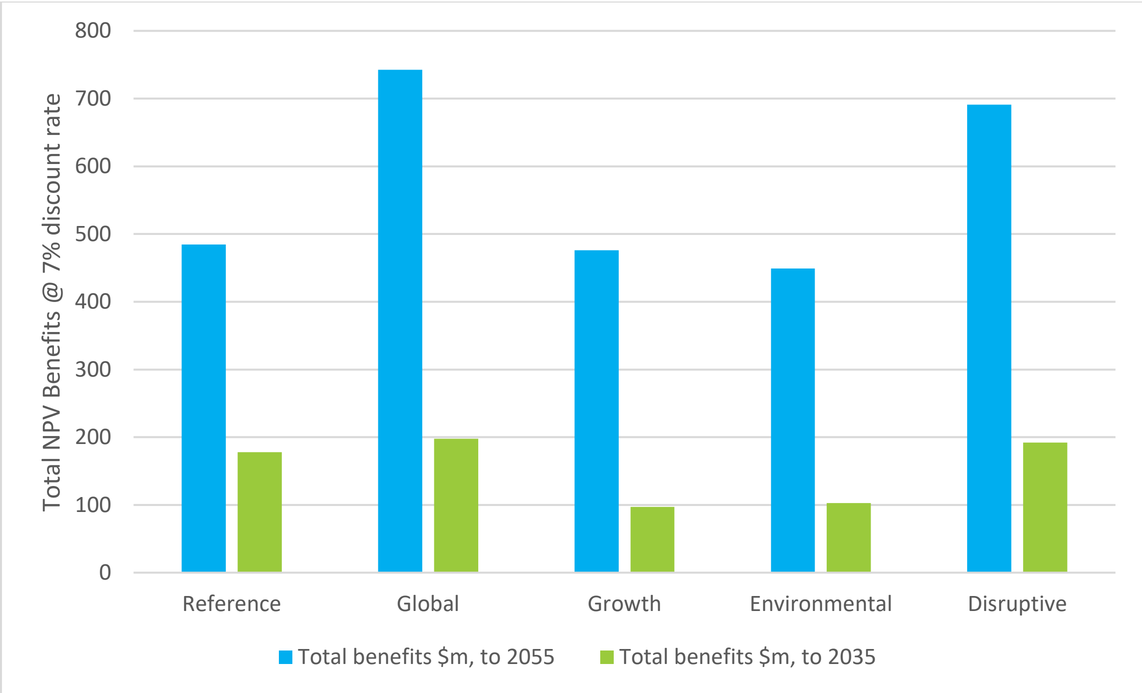


Figure 3: Total NPV benefits from 2022 to 2055 compared to total NPV benefits from 2022 to 2035

7.1.7 Question 5

> b. *Would there be any material market costs if Tiwai exits and Transpower does not upgrade the HVDC? I.e. did the SDDP results show any spill costs? Spill costs are not shown in the spreadsheet, but we understand they may be included in the thermal operating costs. Our initial assessment is that any spill costs would be very low because the thermal operating benefits are low until 2035. Please note that the upgrade can only save up to the increased capacity (120 MW) of spill rather than all the generation that is constrained.*

Transpower response

Material market costs if Tiwai exits and Transpower does not upgrade the HVDC include:

1. The market would be less able to transfer South Island hydro during wet years, resulting in higher thermal costs.

2. The market would be less able to take advantage of the South Island generation during periods of high demand, low wind generation and low solar generation (i.e. HVDC firming). This will result in higher thermal and higher deficit costs.
3. Relevant to late in our modelling scenario (post 2045) the market will be less able to build potentially competitive generation in the South Island.

Transferring South Island generation northwards

In this section of our response, we demonstrate that upgrading the HVDC allows greater South Island generation transfer northwards.

Our generation dispatch modelling forecasts greater South Island hydro generation and HVDC flows with our proposed HVDC upgrades. The upgrades allow greater northwards transfer of South Island hydro generation when water values (or the opportunity cost of water) are lower than thermal operating costs and there is available transfer capacity on the HVDC.

In our response to RFI02, Question 1, Figure 3 we showed, for the Growth Scenario, average South Island hydro generation, across all hydro scenarios, is greater in the factual as compared to the counterfactual. The factual includes:

- Tiwai leaving in 2024
- A fourth HVDC Cable installed late in 2027
- The preferred CNI and Wairakei ring transmission upgrades.

The counterfactual includes Tiwai leaving in 2024 and no changes to the existing HVDC and AC grid.

Greater South Island hydro generation in our factual is largely associated with wet years, when expected inflows are likely to be high, implying water values less than the unit thermal costs. To demonstrate this, Figure 4 shows average and wet year South Island hydro generation differences between the factual and counterfactual for all scenarios. As is our convention, a positive generation difference is where dispatched generation in the factual is greater than dispatched generation in the counterfactual.

Figure 4 shows that South Island hydro generation factual differences are mostly greater for wet years compared to dry years. Also, factual differences *occur well after Tiwai exits*. For some scenarios forecast factual differences become negative around 2045, this will be related to new South Island generation projects 'crowding out' South Island hydro generation. For these years, while South Island hydro generation is less than in the counterfactual, this is compensated by greater quantities of generation from new South Island renewable generation.

Greater South Island hydro generation will be enabled by the full suite of our proposed transmission upgrades. The HVDC will, though, play a critical role. This can be seen by looking at HVDC flows for the preferred transmission upgrade option factual and counterfactual, which is shown in Figure 20 of Attachment D of our submission. We repeat a portion of this figure in Figure 5 for the Growth scenario. This shows increased HVDC flows for both the HVDC Statcom option (e.g. 'Growth_1200MW') and HVDC fourth cable option (e.g. 'Growth_1400MW').

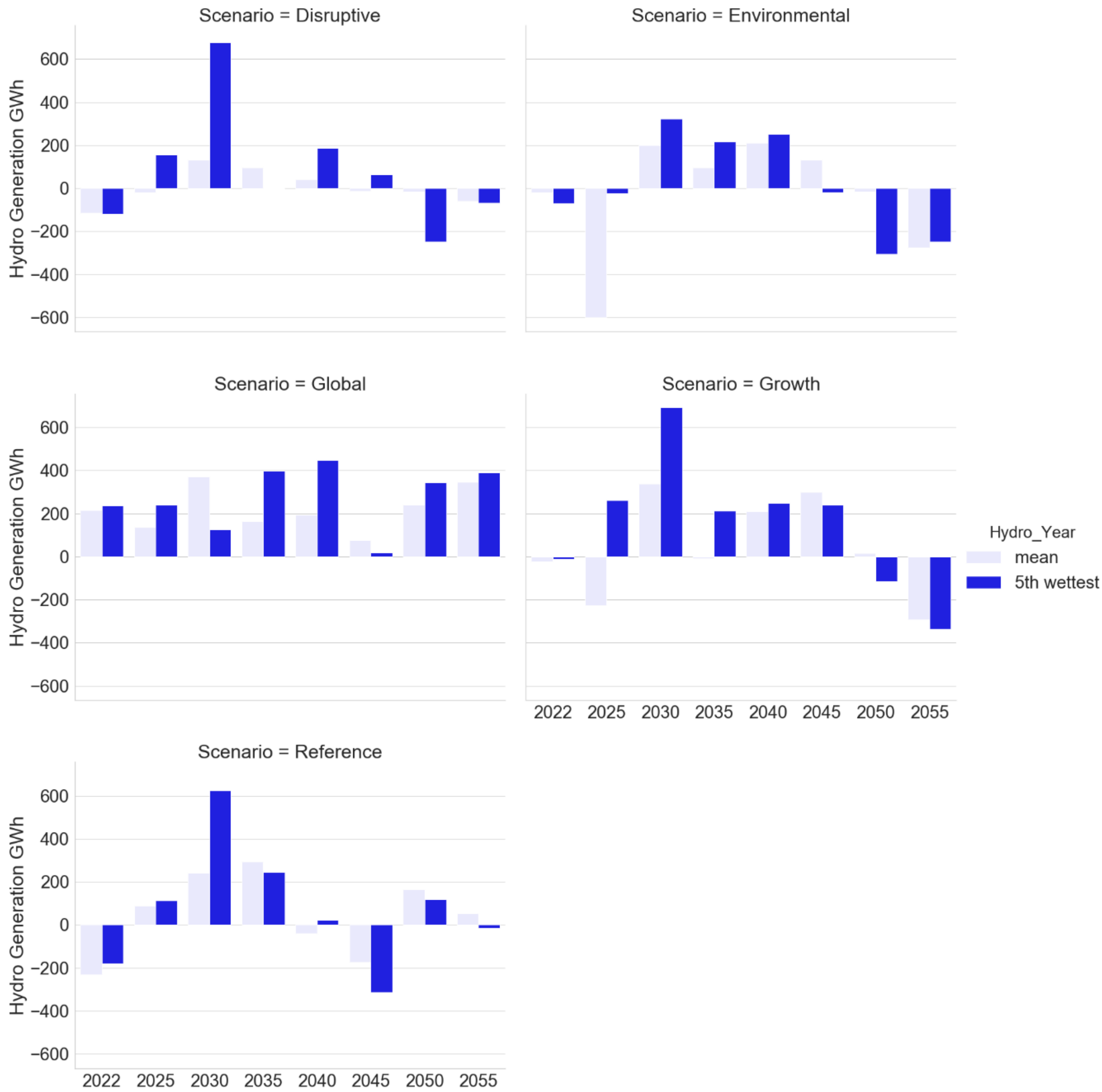


Figure 4: Factual vs. counterfactual generation for average and wet year South Island hydro generation

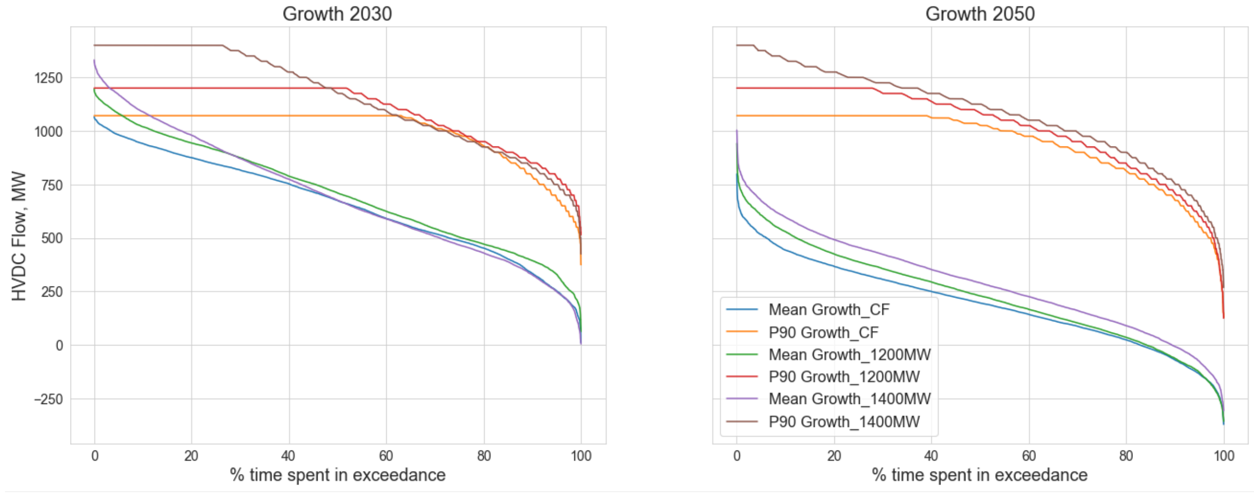


Figure 5: HVDC flows for the preferred option and Growth Scenario (from Figure 20 of the Attachment D)

South Island Hydro Spill

Figure 6 shows forecast South Island hydro spill for the factual, Growth scenario, and for the three main hydro catchments. Spill is dominated by Manapouri which has relatively less storage and ability to respond to high hydro inflows. It is also associated with wet years, as median inflows are considerably lower than wet years (P90 spill).

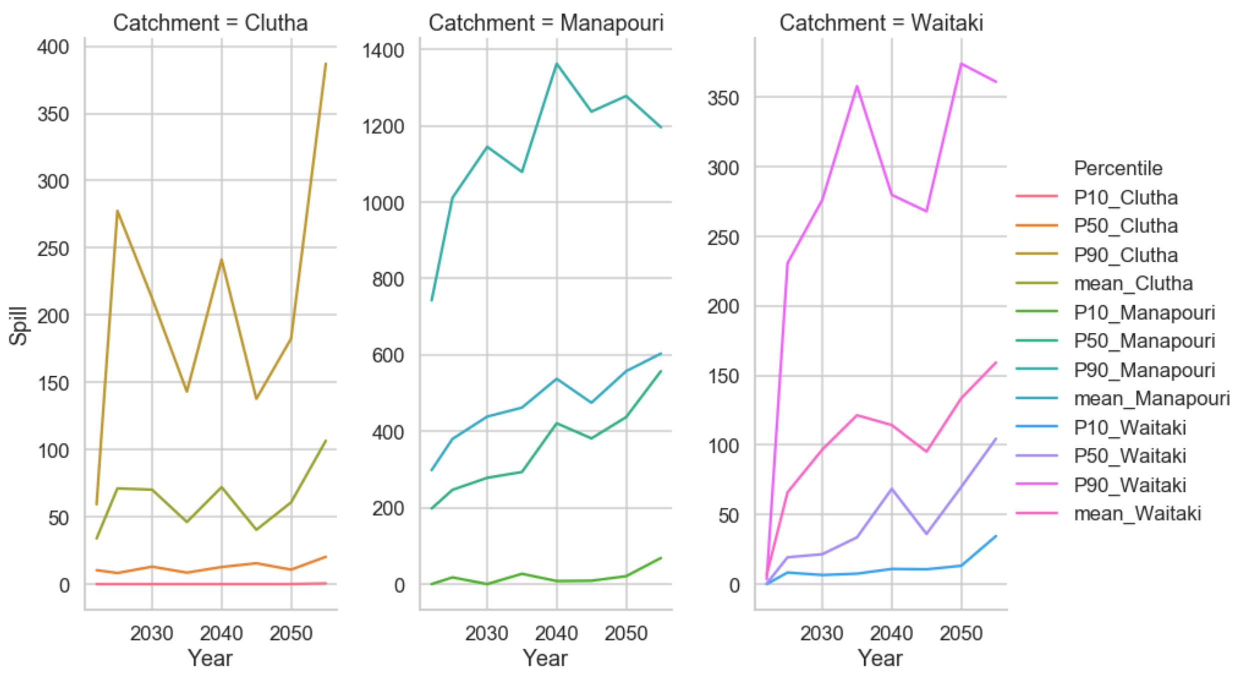


Figure 6: South Island hydro spill for the three main hydro catchments, Growth Scenario

South Island hydro spill increases at first due to Tiwai leaving, which results in an 'excess' of South Island hydro generation, particularly during wet years. Spill does not return to pre Tiwai levels within the modelled horizon. This is most likely due to an increase in wind and solar generation which, with its very low on-going operating costs, will not reduce its output in response to wet years even where hydro energy is plentiful.

Figure 7 shows differences in South Island hydro spill (for the main catchments only) between the factual and counterfactual. The factual and counterfactual are as defined above. There are relatively small differences between factual and counterfactual spills. In 2030, spill is lower in the factual for all scenarios and this does correspond to higher factual generation for this year. For some scenarios spill differences increase post 2040, this is likely related to the factual for these scenarios having greater quantities of (less responsive) installed wind and solar generation.

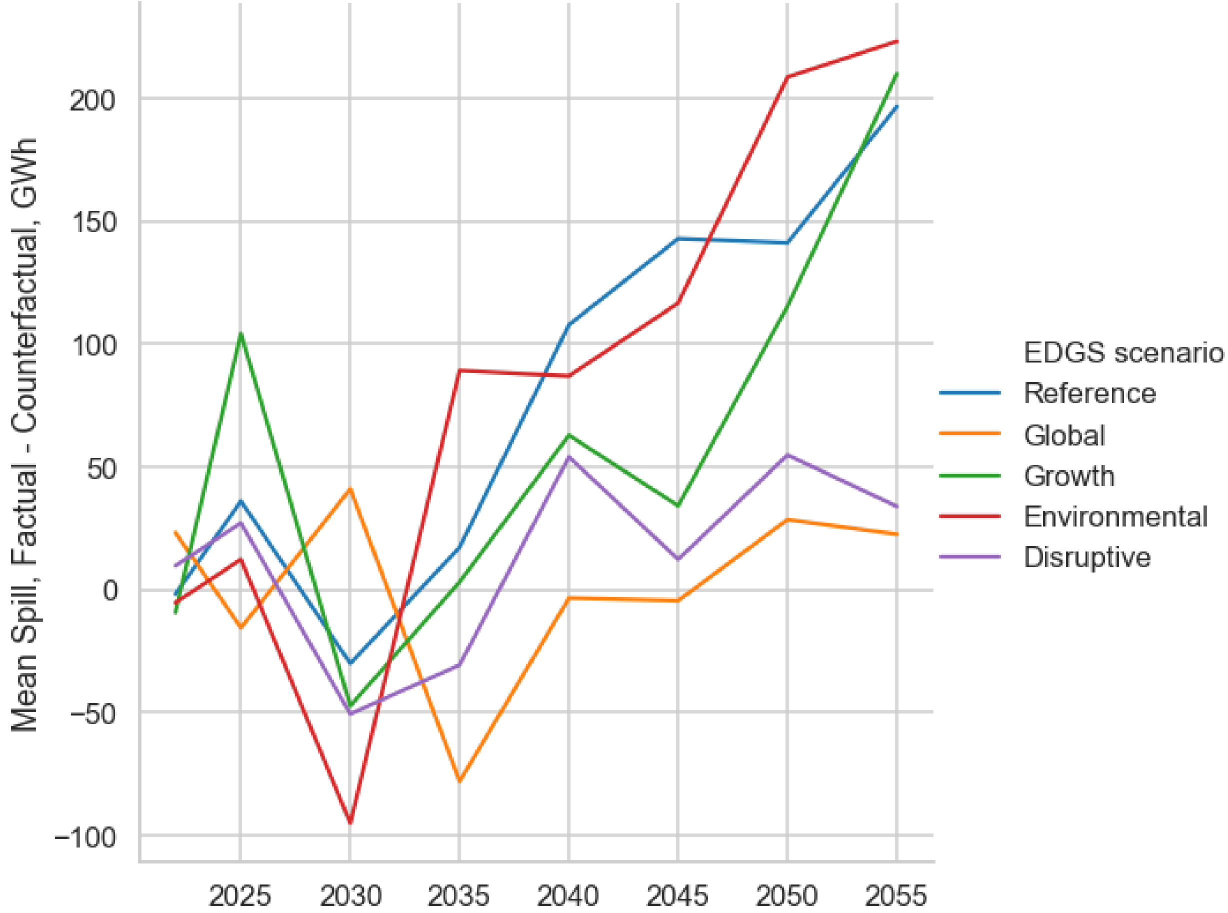


Figure 7: Factual vs. counterfactual generation mean South Island hydro spill

Our generation dispatch modelling does not include explicit spill costs. The dispatch model seeks to minimize electricity system operating costs, for a range of hydro inflows. As part of this process, the model will avoid spill to make better use of hydro inflows and to minimise thermal operating costs.

HVDC Firming

HVDC firming is where the HVDC transfers South Island hydro generation to support North Island demand during periods when North Island wind generation and/or solar generation are low.

Figure 8 shows an example of HVDC firming in action for a day in 2045, with a median hydro inflow sequence and for the 50th worst 'North Island demand residue' peak. Where we define North Island demand residue as equal to North Island Demand minus North Island wind and solar. The North Island demand residue will probably be high for calm, cloudy, winter days. For the day shown in Figure 8 we assume Environmental scenario demand and its associated generation expansion plan. We also assume that the HVDC fourth cable has been installed along with the preferred AC transmission upgrades.

Figure 8 shows that from afternoon onwards as both wind and solar decline, South Island hydro generation responds by ramping up generation, increasing HVDC Northwards transfers. HVDC transfers peak at 1330 MW, exceeding the existing capacity of the HVDC.

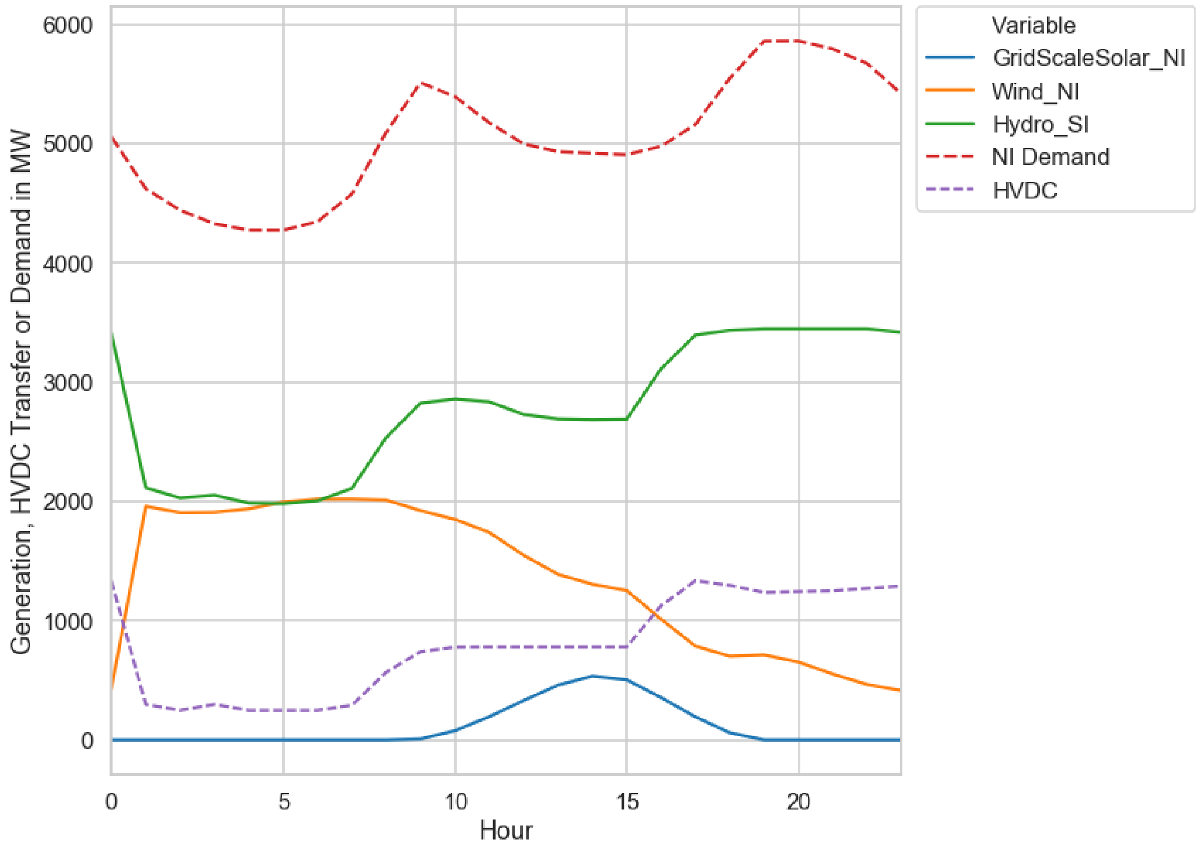


Figure 8: Generation, HVDC transfers, and demand for a day in 2045. Assumes Environmental scenario, median hydro inflows and the 50th worst North Island demand residue.

To further demonstrate HVDC firming we have compared factual and counterfactual generation, HVDC transfers and deficit averaged over the worst 100 'North Island demand residue' peaks. The factual and counterfactual are as defined above, and we have done this comparison for the Growth scenario and for median hydro inflows. Figure 9 shows this comparison for hydro generation, HVDC transfers, fossil and biofuel generation and for deficit. Factual hydro generation and HVDC transfers are somewhat higher compared to the counterfactual which results in both lower fossil and biofuel generation and deficit.

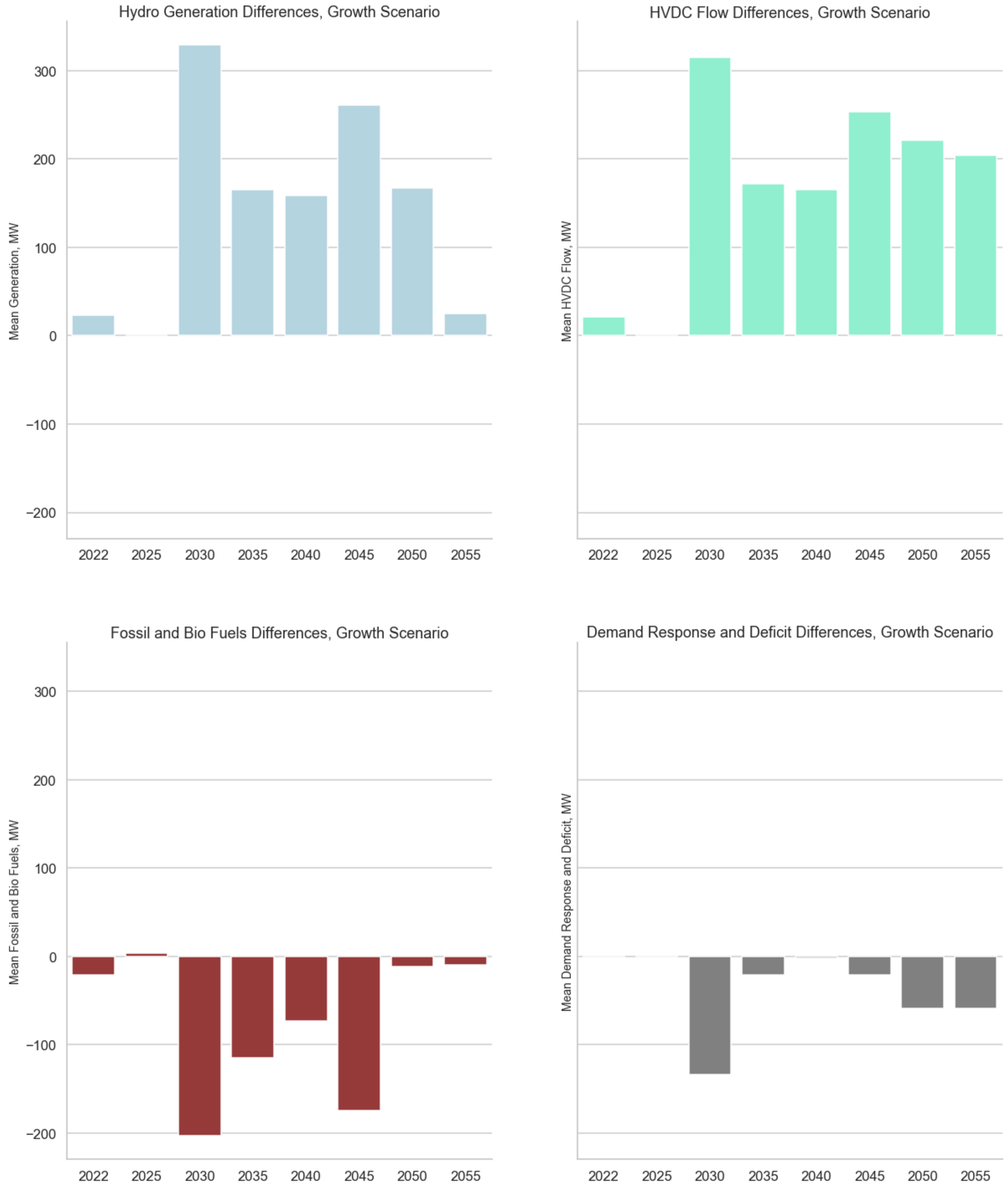


Figure 9: Factual vs counterfactual comparisons averaged over the worst 100 North Island demand residues. Assumes the growth scenario and median hydro inflows.

Figure 10 shows corresponding factual average HVDC transfers for our worst 100 'North Island demand residue' peaks. Transfers exceed the existing capacity of the HVDC for most years post 2030.

Figure 10: Factual HVDC inflows averaged over the worst 100 North Island demand residues. Assumes the growth scenario and median hydro inflows.

7.1.8 Question 6

> c. *How are the benefits from the firming function of the HVDC reflected in the benefits?*

Transpower response

As discussed above where the HVDC plays a firming role thermal costs and deficit costs will reduce. The extent to which this will occur will depend on the extent to which South Island hydro can compete with thermal and demand response during calm, cloudy winter days.

7.1.9 Question 7

Given that the Tiwai exit may not provide any material costs to the market with the current HVDC transfer limits, as show in the Figure 19, but upgrading the HVDC will incur a material transmission charge to the consumer (and eventually the consumer pays all transmission charges):

> a. *have you assessed the economics of market cost of Tiwai exit with HVDC upgrade vs cost to consumers after the HVDC is upgraded; and*

b. *are the any other factors that are driving the HVDC upgrade?*

Transpower response

Although NZGP1.1 was started as a Transpower response to the potential Tiwai closure at the end of 2024, the emphasis has changed. Tiwai's closure in 2024 (or later) is no longer the key driver of the overall benefits from NZGP1.1.

Load growth has been higher than assumed at the start of NZGP1.1. This, combined with low levels of new generation development and the completion of the CUWLP work, mean that the large amounts of hydro spill we have previously seen in our modelling, once Tiwai closes, are less likely. We would still expect significant hydro spill in wet hydrological years.

Our modelling indicates that varying Tiwai's exit date does not have a significant impact on the overall benefits for NZGP1.1. Indeed, the modelling we have undertaken demonstrates that most of the benefits of our proposal arise from supporting a highly renewable and intermittent electricity system, such as required if New Zealand is to achieve its net zero carbon by 2050 goal.

Our modelling indicates that electricity flows from the South Island to North Island increase as we remove thermal generation from our system. Most new generation is intermittent and built in the North Island. South Island hydro generation plays a significant role in firming the North Island's generation.

The benefits included in our analysis mostly arise from a more reliable HVDC transfer capability and pushing more north transfer onto our 220kV network, with lower transmission losses. Our analysis shows that our proposed NZGP1.1 upgrades maximise net benefits for the investment need and that the net benefit is positive. Further, NZGP1.1 also enables new generation, and is a low regret option, rather than being a 'just-in-time' investment.

The timing of our proposed investments has been determined by other factors, rather than being an outcome of the analysis. Planning and implementing the large projects anticipated in our major capex projects is complex from a technical, procurement and workforce point of view.

As we expect our workload, across our base work and MCPs, to continue to increase as New Zealand electrifies, we need to efficiently utilise resources. Leaving our work to just-in-time risks inefficient outcomes by not having resources available to complete the work to meet the need or compromising other work programmes.

In the case of NZGP1.1, the need for outages to undertake upgrades on core elements of the grid is difficult, the need to schedule our specialised workforce and the need to procure equipment have all influenced the timing.

We have discussed the difficulties the need for outages and scheduling our workforce create, before. Delivery risks around supply chain issues is an emerging issue that our investment plans need to account for. Disconnectors are now taking as long as a transformer, to be delivered to New Zealand. Sub-sea cables and equipment such as Statcoms are also in high demand with increasing lead times.

Figure 11 summarises the electrification spend expected in some large countries. What that means for us is that sourcing equipment is becoming increasingly difficult and availability of equipment could become a significant determinant in the timing of our investments. In our view, these and such issues which have influenced the timing of investment in our NZGP1.1 proposal are likely to remain as determinants for the foreseeable future and we will be unable to apply the just-in-time requirement of the Capex IM.

Figure 11: New Zealand's electrification needs will be costly but we are small on a global scale

---

8.0 RFI008 – received 28/3/2023

8.1.1 Question 1

In your response to RFI02 dated 17 March 2023 you state that:

"The justification for this investment is that increasing HVDC transfer capability (using that term to differentiate it from HVDC transfer capacity, which is primarily to do with the HVDC converters themselves) from the recent historic average of 1071MW to nearly 1200MW provides a benefit, along with the CNI upgrades. The investment involves installing a new STATCOM at Haywards, which will provide redundancy for synchronous condenser outages along with new filter banks, which will provide redundancy for the filter banks."

We seek more information about the benefits of increasing HVDC capability from 1071MW to 1200MW. Can you provide us with the following information:

a. *Using the disruptive scenario without the HVDC investment (i.e., consider the HVDC capability is constrained to 1071MW), can you please perform an SDDP economic analysis for 2027 and 2034? The study should be done at a P50 HVDC transfer level.*

If this analysis has already been performed, can you please provide us with the difference in economic benefits for 2027 and 2034, for the HVDC capability constrained to 1071MW and 1200MW?

Transpower response

We have calculated yearly benefits for the disruptive scenario for 2027 and 2034.

We have averaged yearly benefits over all hydro scenarios rather than provide the benefits for the P50 HVDC transfer level, as discussed with Commission staff. Modelling uses an hourly resolution and 50 synthetic hydro inflow sequences (see Section 3.1.3 of Attachment D of the submission for further explanation).

For this modelling our factual includes:

- Tiwai leaving in 2024
- A statcom installed at the beginning of 2026
- The preferred CNI and Wairakei ring transmission upgrades.

The counterfactual includes Tiwai leaving in 2024 and the existing HVDC and AC grid.

Benefits are equal to counterfactual costs minus factual costs and are provided in Table 1.

Cost Category	2024	2027
Capital and fixed operating cost reductions,	$3,120	-$1,803,222
Thermal cost reductions	$5,527,525	$7,462,183
Emission cost reductions	$3,995,308	$7,658,728
Deficit cost reductions	-$49,301	$8,020,987
Loss cost reductions	$2,523,793	$6,765,889

Table 1: Disruptive scenario benefits for 2024 and 2027

8.1.2 Question 2

b. *Please provide us the expected annual spill in MWh if Tiwai leaves in 2024 until the new STATCOM is installed, assuming P50 HVDC transfer.*

Transpower response

We attach, in the spreadsheet 'rfi08_spill_summary.xlsx', annual spill for the disruptive and global scenarios for 2024 through to 2030 for the factual, as defined above. These results are derived from yearly dispatch modelling 'snapshots' using an hourly resolution.

Mean annual spill, for the disruptive and global scenarios, summed over the Clutha, Waitaki and Manapouri catchments is shown in Figure 1.

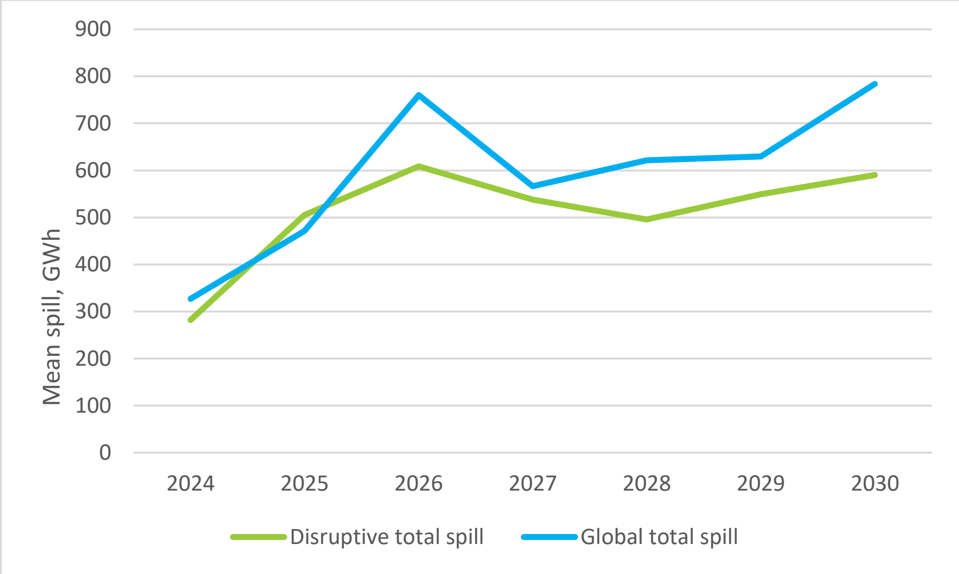


Figure 1: Main South Island catchments total mean spill for the disruptive and global scenarios

8.1.3 Question 3

The draft RCP4 proposal indicates you are proposing $62m for replacement of capacitor banks, major refurbishment of the synchronous condensers and refurbishment of 3rd SVC. Your response to RFI02 suggests that the HVDC investment will increase HVDC transfer capability during this refurbishment and also after the refurbishment.

c) *Taking into account the much improved reliability and capability HVDC once the proposed works are carried out under draft RCP4 proposal, to what extent has this been acknowledged in the preparation of HVDC works in the NZGP1.1 MCP proposal?*

d) *If you have accounted for the investment under proposed draft RCP4, can you please provide the net benefits for the additional investment in the HVDC under NZGP1.1 proposal?*

We are also interested in your statement about the additional benefits that may accrue due to the NZGP1 HVDC investment. In your most recent response to RFI02 you have stated that:

"Both wind and solar generation are intermittent, and our modelling indicates an increasingly important role for South Island hydro to firm that generation. That in turn implies an increasingly important role for the HVDC and the Stage 1 HVDC investments improve the reliability of HVDC transfer capability."

e) *Can you quantify the economic benefit of increased HVDC availability that allows South Island hydro to firm intermittent North Island wind and solar generations?*

Transpower response

Our analysis assumed that HVDC transfer capacity will increase from 1071MW to 1200MW as a result of the proposed NZGP1.1 HVD investments. This is a proxy for an expected increase in transfer capability resulting from providing redundancy for the existing voltage support equipment and filter banks.

The improved reliability of the existing voltage support equipment following the RCP4 refurbishments has not been considered in our analysis. We expect there to be a reliability improvement which will reduce future refurbishment costs and this is where that benefit will show up. Although ongoing O&M costs for the HVDC are included in our analysis, we have not allowed for it in our analysis.

The HVDC transfer capability increase provided by our Stage 1 investments is static over time. This is an approximation, because as suggested in the question, over the entire study period the probability of outages from equipment outages varies as the average condition of the equipment changes. Although our approach is an approximation, we consider it reasonable because it would be infeasible to estimate year-to-year outage probabilities with any reasonable accuracy. In addition, assessing increases in HVDC transfer capability much less than that considered, with SDDP, may not be plausible. The model would be unlikely to differentiate 10 or 20 MW changes, for instance.

In response to e), we can estimate the economic benefits of HVDC firming. This could be done by identifying those hours where the HVDC is acting in this role. This will require a reasonable amount of results processing and will take approximately 3 – 6 business days.

8.1.4 Question 4

In your most recent generation expansion plan, the assumptions about South Island generation development have been modified.

Previously your modelling information suggested that South Island generation development out to 2040 could include up to 400MW of new generation capacity. Your most recent information in the generation expansion plan suggests that this assumption has changed to 50MW by 2024 and 57netMW by 2037.

We would also like to understand what the South Island demand increase assumptions are in your modelling so we might understand the potential South Island generation surplus.

a) Could you please provide us with your South Island demand increase assumptions per annum between 2024 and 2040?

b)

Transpower response

We attach South Island forecast demand for each scenario in the spreadsheet 'rfi08_si_demand.xlsx'.

8.1.5 Question 5

The proposed NZGP1 MCP states that the HVDC would provide firming of North Island intermittent generation after the North Island thermal generations are decommissioned. Can you please confirm if Transpower has undertaken any detail study of HVDC's future firming role when North Island thermal generations are decommissioned.

c) *Please confirm whether any firming role of the HVDC is not expected until after the 2030s when most of the current thermals would be decommissioned.*

Transpower response

With reference to Figure 9 in our response to RFI07 we expect the proposed HVDC upgrades will provide some firming from approximately the date of their installation. The importance of this role will increase with greater quantities of intermittent renewable generation.

Our generation dispatch modelling considers hourly variations in demand, wind, and solar generation as well as multiple hydro inflow sequences. As such, we argue that it is a detailed study of the HVDC's future firming role. That said, there is scope to improve the quality of the analysis by considering shorter term - within the hour- variations in demand and intermittent renewable generation. While we have yet undertaken such an analysis, we expect that this would further highlight the importance of the firming providing by our proposed upgrades of the HVDC.

8.1.6 Question 5

d) *After the current thermals are decommissioned, would the biofuel North Island thermal generators forecasted in the generation expansion plan be able to perform this function? If not, why not?*

Transpower response

The installed capacity of biofuel generation could be increased to reduce or remove the need for the firming providing by our proposed HVDC upgrades. This would though increase both overall capital and operating costs relative to our proposal.

More generally, North Island thermal generation, grid scale batteries, hydro generation (with storage) and demand response can all provide firming support for intermittent renewable generation. All these technologies are considered in both our generation expansion and generation dispatch modelling. The extent to which they are installed or dispatched in preference to additional HVDC capacity or transfers will depend on their relative economic merits. These trade-offs are taken into account in the benefits we have presented in our proposal.

9.0 RFI009 – received 19/4/2023

9.1.1 Question 1

Consistent with cost-benefit studies, the Capex IM requires that the costs and benefits of all proposed staging projects and model projects are included in the investment test.

*It appears that these may not be the case. For example, for the new transmission line from BPE (**new BPE line**) that the market (capital + O & M) may not be included in the CNI sheet of the NZGP1 MCP Investment Test spreadsheet. These should be included either as a future stage cost or a modelled project cost in all investment options.*

Please advise whether, and if so where, the cost of the new BPE line (estimated to be $588 million) is included in the investment test.

Transpower response

The cost of a new BPE line (estimated to be $588 million) is included in the Investment Test options which include a new line only. It is not included in the proposal.

We have shown a new line north from BPE as a "possible Stage 3" project, because it is not economically justified using the modified EDGS, but could be economic under other scenarios. As discussed in our proposal, we have used modified EDGS in our application of the Investment Test, as required by the Capex IM, but are not confident these capture the full range of future uncertainty. We have included a request for preparedness funding in our proposal to advance investigations most relevant to the uncertainty not reflected in the modified EDGS.

9.1.2 Question 2

If the new BPE line is not included as a cost element in the investment test, then its impact should not be included as a benefit element in the investment test. Please advise whether or not the impact of this line (which is the additional transmission capacity provided by the new BPE line) is included as a benefit element in the investment test and advise the capacity used in the studies.

Transpower response

The benefits of a new BPE line (estimated to be 2400 MW capacity2) are included in the Investment Test options which include a new line only.

[2] See Figure 21, in Attachment D of the application.

9.1.3 Question 3

The same applies to other cost or benefits elements in the Wairakei and the HVDC costing. Please confirm that all costs and benefits elements are included in the investment test.

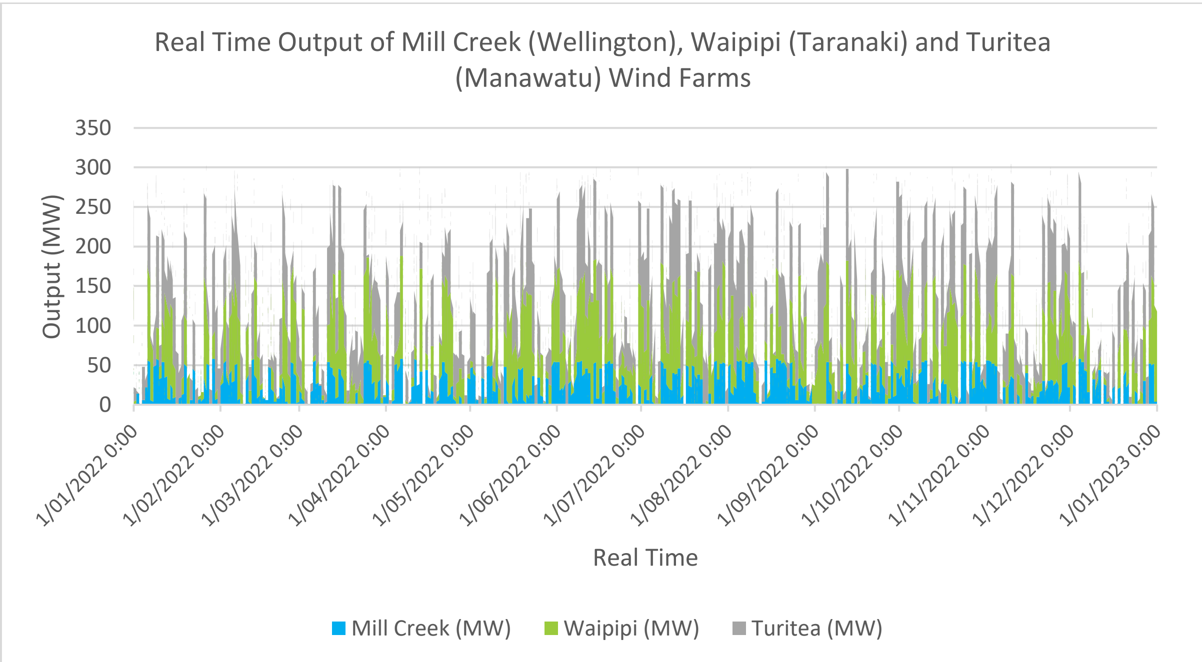
Transpower response

The costs and benefits included in the Investment Test, for Wairakei Ring and HVDC options, reflect the enhancements made in that option only.

9.1.4 Question 4

The generation expansion plan (a spreadsheet that Transpower provided) shows that more than 1.9 GW of additional generation is proposed for the Lower North Island (i.e. Region 2). Stage 1 investments are expected to increase the north transmission capacity from 750 MW to 1350 MW or a net increase of about 600 MW. If the impact of the new BPE line is not included in the investment test, then please reconcile how 1.9 GW of new generation will be exported out of BPE to the northern load centres when the net increase in capacity is 600 MW.

Please note that our review of the real time outputs of three geographically dispersed wind farms – Mill Greek in Wellington, Turitea in Manawatu, and Waipipi in Taranaki - shows there is significant correlation. Refer to the graph below. This means we could expect simultaneously high outputs of all wind farms in this region with the transmission network requiring a level of capacity that matches the install capacity of wind generation.



Transpower response

We agree that our modified EDGS include approx. 1.9 GW of generation in the lower NI – almost all of it being wind generation. We also agree that the enhanced CNI lines will have a transfer capacity north of approx. 1.4 GW. When the lower NI wind generation is producing at maximum, that generation is not only exported north, but is also exported south i.e. HVDC transfers are from north to south. The combined north (CNI) and south (HVDC) transmission capacity exceeds the capacity of lower NI generation.

Reconciling generation and circuit flows in the lower North Island

We confirm that generation and circuit flows reconcile in the lower North Island. To demonstrate this, we have considered the Growth scenario, with the HVDC fourth cable installed in 2027 and with the proposal's preferred AC grid transmission investments. These transmission investments do not consider a new line. We have focussed on the 220 kV grid bounded by Haywards and Bunnythorpe ("the HAY-BPE region"), as shown in Figure 1, and use hourly modelling results for 2045.

As of 2045, there is 2059 MW of wind generation[3] connecting into the HAY-BPE region. This covers the bulk of wind generation in the lower North Island. It includes 966 MW of repowered wind farms and the Turitea wind farm.

There is a further 570 MW of lower North Island wind generation in 2045, outside of the HAY-BPE region. This generation connects into the MGM (100 MW), TKU (250 MW) and WDV (Repowered Te Apiti, 220 MW) busses. As this generation is less relevant to the CNI corridor it has been

---

[3] As of 2045 all existing wind farms have been decommissioned and repowered. The X MW of wind generation includes the full, gross, capacity of each repowered wind farm (rather than the net additional generation capacity).

excluded in our analysis for simplicity. The relationship between forecast generation and flows into and out of HAY- BPE region should, if our model is correct and energy is conserved, be as follows:

Generation + DC Flows (+ve into the region) + Battery Flows (+ve for injections) = Region Demand + Circuit Flows (+ve out of the region)

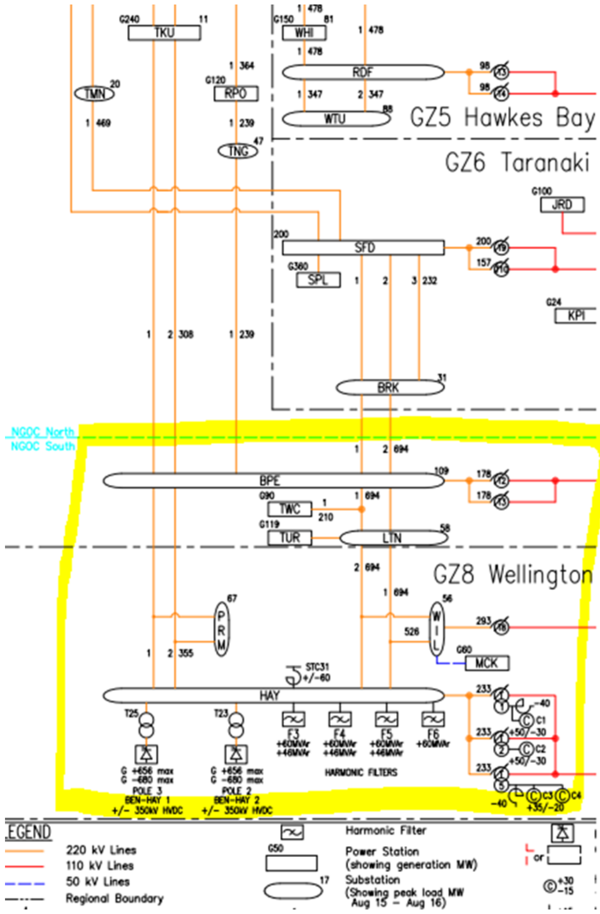


Figure 1: Portion of the 220 kV grid - highlighted in yellow – used to demonstrate generation and circuit flows reconcile.

We have plotted these parameters for a single hydro inflow sequence and for a portion of 2045 in Figure 2. The top chart shows average daily generation and flows for the HAY-BPE region for the first 72 days of 2045. The bottom chart shows the hourly generation and flows for the first 72 hours. Generation and circuit flows reconcile and follow the formula above.

Key takeaways for this analysis are as follows:

- Generation and circuit flows balance
- When the wind generation is high HVDC flows are either low Northwards or in some cases Southwards.
- Wind generation is closely correlated, the maximum combined wind generation in 2045 is 2027 MW (for our selected hydro inflow sequence).
- Maximum circuit flow for the CNI corridor in 2045 is 1455 MW (for our selected hydro inflow sequence). The CNI corridor includes the BPE-TKU, BPE-TNG and BPE-BRK circuits. This is consistent with Figure 21, in Attachment D of the application.

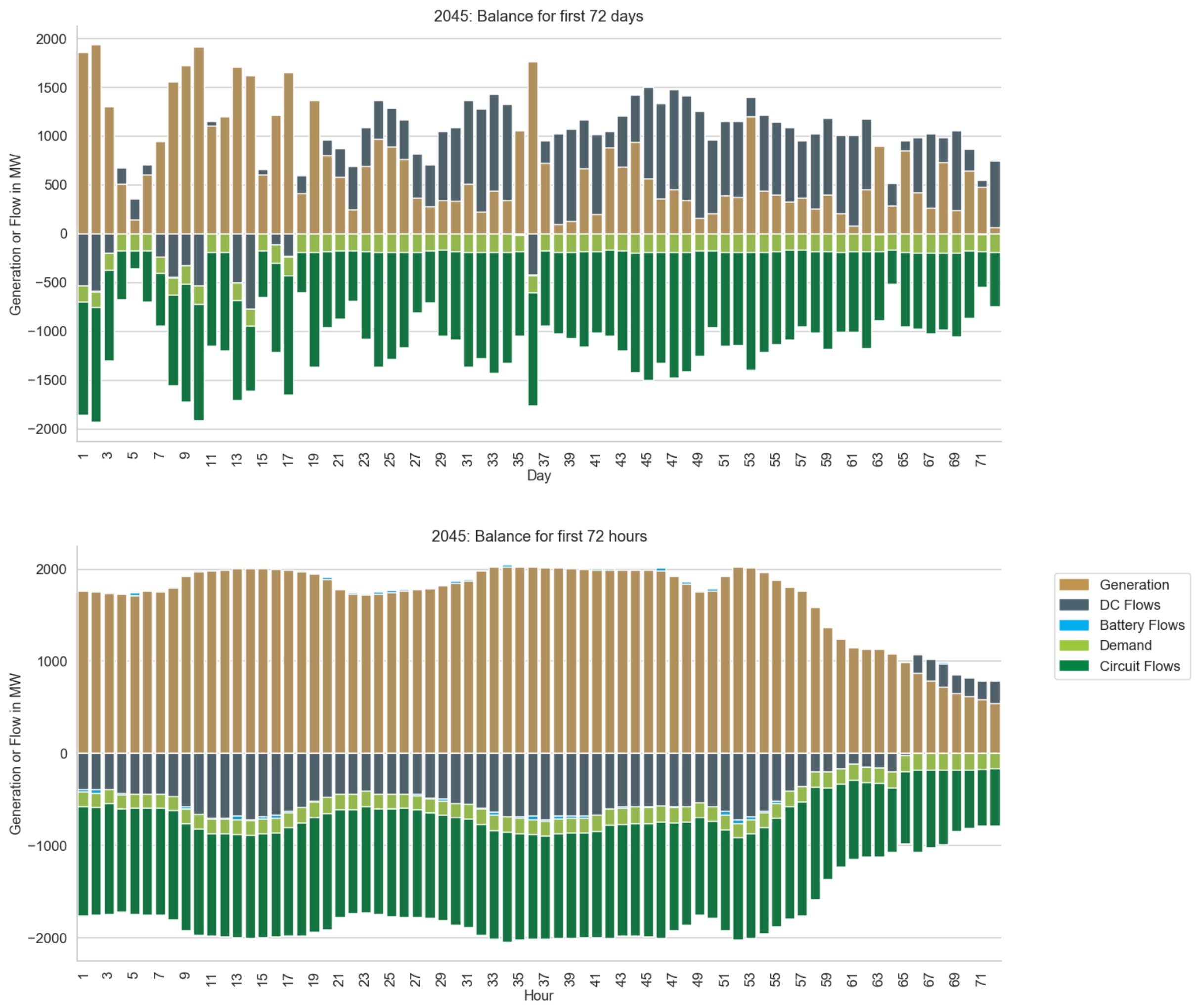


Figure 2: Generation, battery flows, HVDC flows and demand for the HAY-BPE region.

Wind generation Variability

We confirm that our modelling incorporates wind variability and type of behaviour shown in the Commission's chart. A full description of this approach is provided in TPM Determination BBC Assumption Book[4]. To provide an idea of model wind variability, Figure 3 shows wind generation for the Castle Hill wind farm in 2045, for our selected hydro inflow sequence. Different inflow sequences have different wind profiles, although the variability will be similar.

[4] Available here. See Section 2.3.4.5, from paragraph 112 onwards.

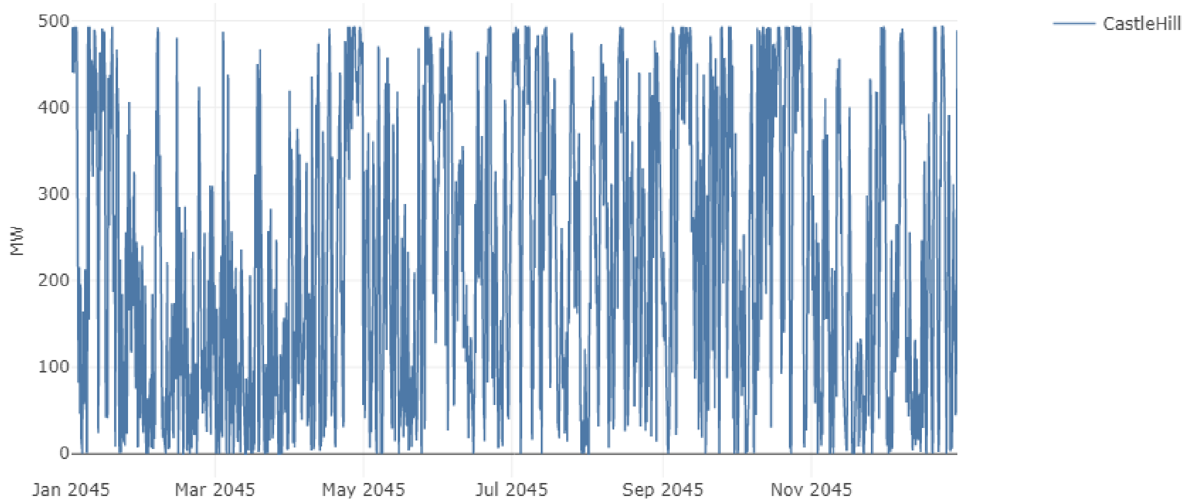


Figure 3: Castle Hill wind generation, 2045 for our selected hydro inflow sequence.