Net Zero Grid Pathways 1

Major Capex Project (Staged) updated

Attachment D: Scenario & Modelling Report

Date: 25 September 2023

Contents

1.0 Introduction

This document is the Modelling report for the Net Zero Grid Pathways Stage 1 Major Capex Proposal (NZGP1.1 MCP).

This document describes the scenarios used and modelling performed to identify the respective needs, components we considered for this project, and how these components were evaluated to determine our short-list. It is one of the supporting attachments for our main report (NZGP1.1 MCP) and should be read in conjunction with the main report.

Investment Proposal

- Attachment A – Compliance Requirements
- Attachment B – Power Systems Analysis
- Attachment C – Options Report
- Attachment D – Scenario & Modelling
- Attachment E – Costing Report
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2.0 Scenario assumptions

2.1 Introduction

This section describes the demand and generation scenarios that underpin our NZGP1 benefits analysis.

This MCP investigation complies with the requirements of the Capex Input Methodology (Capex IM) which requires Transpower to use the Electricity Demand and Generation Scenarios (EDGS), as published by MBIE, or reasonable variations of EDGS.

Since we commenced out NZGP1 investigation in 2020, we have reviewed the EDGS 2019 and consulted on variations to the EDGS. This process is described in detail in the NZGP1 Scenarios Update, published in December 2021[1].

This section summarises our reasonable variations of the EDGS 2019 with updates for our application proposal.

2.2 EDGS scenarios 2019

EDGS are a description of five hypothetical future scenarios, relating to forecast electricity demand and generation. They are published by MBIE, specifically for the purpose of investigating major capex proposals. MBIE developed the current EDGS in 2019 and they include the following five scenarios:

1. **Reference:** Current trends continue

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

2. **Growth**: Accelerated economic growth

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

3. **Global:** International economic changes

[1] NZGP1 Scenarios Update

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

4. **Environmental:** Sustainable transition

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

5. **Disruptive:** Improved technologies are developed

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

Figure 1 shows the EDGS 2019 national demand[2] forecasts by scenario, but with Tiwai exiting in 2024.

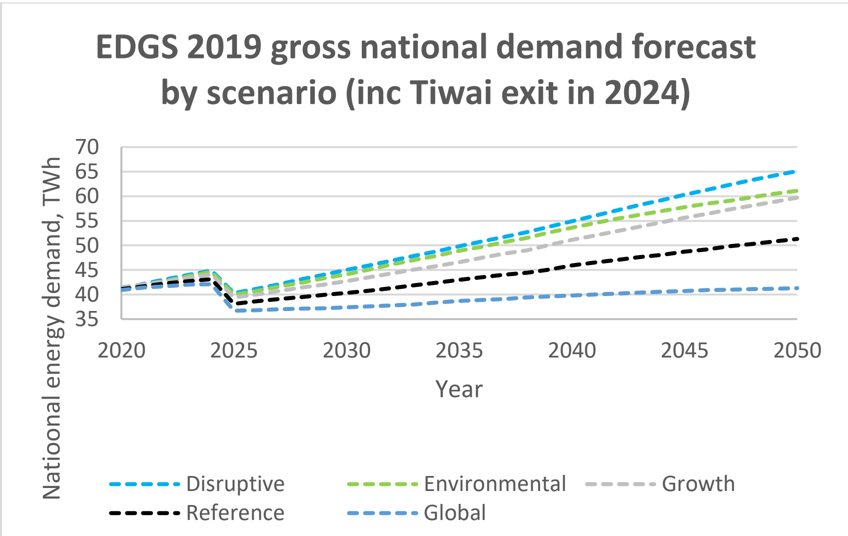

Figure 1: EDGS 2019 national demand forecasts by scenario

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

2.2.1 Tiwai closure

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

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

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

Since then, aluminium prices have remained high, but Meridian and Contact have announced and progressed their plans for a large hydrogen production facility in Southland[3] and Rio Tinto have made their plans for Tiwai closure at the end of 2024, public[4].

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

We have undertaken a sensitivity where Tiwai closes in 2034, rather than 2024, to understand whether our prudent assumption would affect the preferred option (see section 3.3.5).

2.3 NZGP1 demand scenarios

We consulted with the industry on reasonable[5] variations to the EDGS 2019 demand forecasts, to ensure they were up to date and published these in December 2021. Since then, there have been other changes affecting our forward view of electricity demand, so we have made some minor adjustments. We have:

- Updated the historical data that informs our base load demand forecast.
- Updated our view of future demand at each Grid Exit Point (GXP) through discussion with our customers. This is a regular and annual process used to inform demand forecasts for our Transmission Planning Report. We summarise below the changes we have made to long term demand growth and anticipated demand step-changes. The most significant

[3] www.southerngreenhydrogen.co.nz

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

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

change is in Auckland where some step-changes in new demand are occurring earlier than initially expected.

- Included replacement of the Marsden Point oil refinery by a storage terminal.
- Included retirement of Kawerau pulp and paper mill.

Table 1 shows the original EDGS 2019 gross national demand forecast in 2050 (TWh), the changes included in the EDGS 2019 variations and the changes since then which make up our NZGP1 gross national demand forecast in 2050.

Table 1: Summary of EDGS scenarios

	EDGS scenario				
Gross national demand in 2050, TWh	Reference	Growth	Global	Environmental	Disruptive
EDGS 2019	57	65	47	67	71
Tiwai closure	-5	-5	-5	-5	-5
Variations due consultation	0	-4	2	-2	-2
EDGS 2019 variations (published in December 2021)	52	56	44	60	64
NZGP1 variations					
- Baseload forecast	-0.64	0.33	0.20	0.14	0.77
- Auckland step-jumps	0.45	0.45	0.45	0.45	0.45
- Marsden Point closure	-0.24	-0.24	-0.24	-0.24	-0.24
- Kawerau closure	-0.54	-0.54	-0.54	-0.54	-0.54
NZGP1	51	56	44	60	64

Diagrammatically, the original EDGS 2019 demand forecasts are shown in Figure 2 and Figure 3 along with our published EDGS 2019 variations and our proposed NZGP1 forecasts. Figure 2 shows the same data as in Figure 3, but all series are included on the same graph.

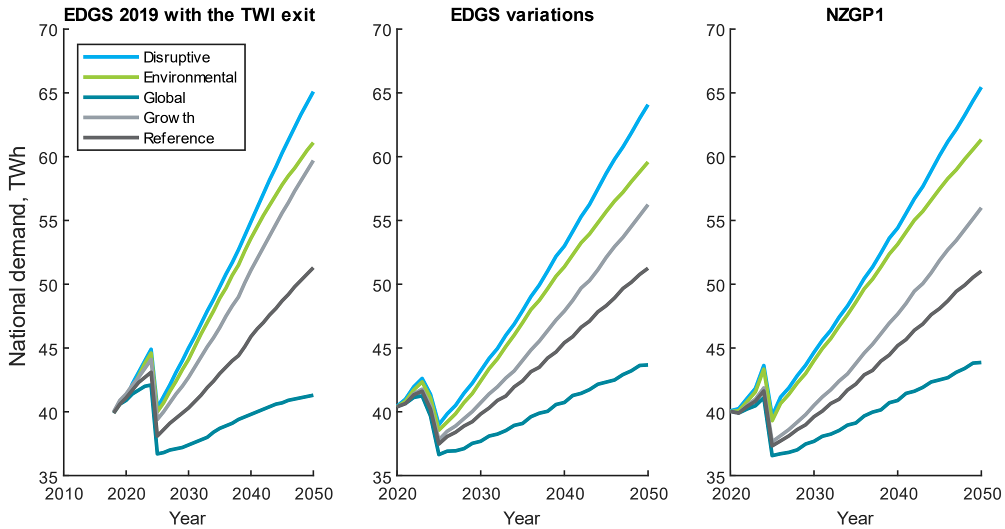

Figure 2: Comparison of the published EDGS 2019 (but with Tiwai exiting in 2024), our EDGS variations and proposed NZGP1 demand forecasts

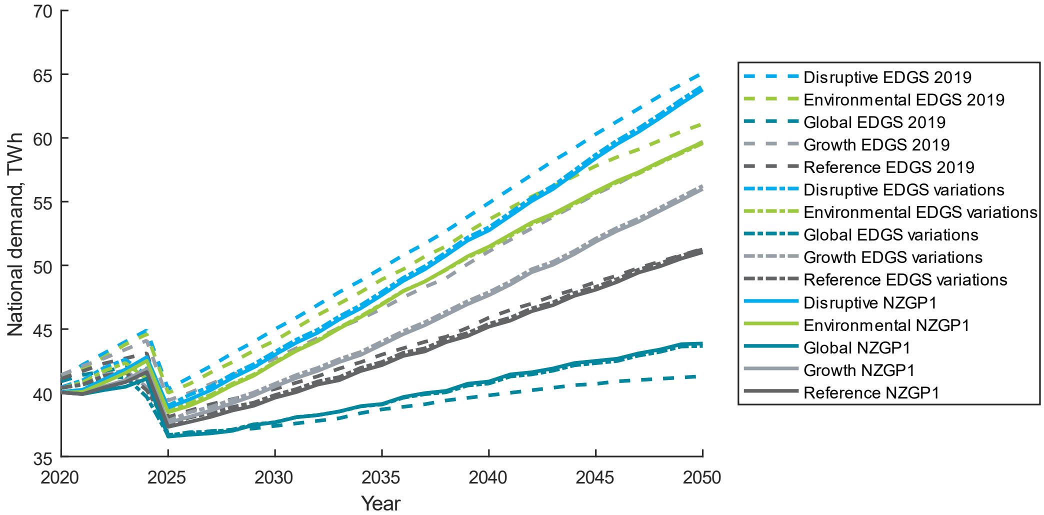

Figure 3: Comparison of the published EDGS 2019 (but with Tiwai exiting in 2024), our EDGS variations and proposed NZGP1 demand forecasts

2.3.1 Comparing the EDGS to other demand forecasts

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

For comparison, we show our proposed NZGP1 demand forecasts with the Climate Change Commission's (CCC's) forecasts and Transpower's own Whakamana I Te Mauri Hiko (WiTMH) forecasts in Figure 4 below.

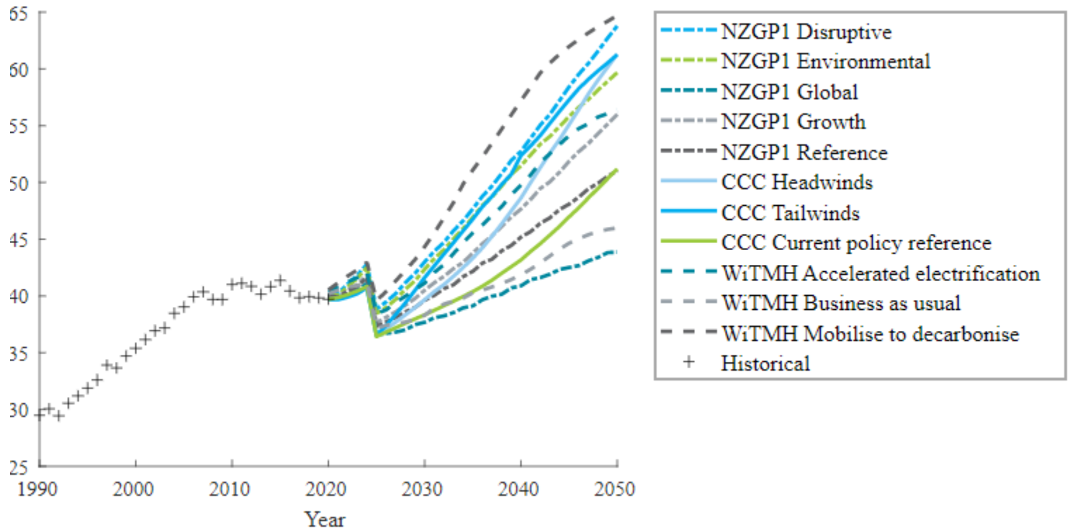

Figure 4: Comparison of NZGP1 demand forecasts, with CCC and WiTMH forecasts

We can make several interesting observations from Figure 4:

- The range of gross national demand forecasts in our NZGP1 scenarios cover the full range of demand uncertainty between the other scenarios, excepting the WiTMH Mobilise to Decarbonise scenario.
- We note that the EDGS Global and Reference scenarios, the CCC's Current Policy Reference scenario and the WiTMH Business as Usual scenario are not aligned with a net zero carbon by 2050 target, whereas the other scenarios are. The weighted average demand of our NZGP1 forecasts (varied EDGS forecasts) is 55 TWh. The average of the CCC's aligned scenarios (Headwinds and Tailwinds) scenarios is 61 TWh and the weighted average of the WiTMH aligned scenarios (Accelerated electrification and Mobilise to decarbonize) scenarios is also 61 TWh.
- In our Investment Test analysis, we will study and report each scenario separately, along with a sensitivity where the WiTMH Mobilise to Decarbonise scenario is reported as a sensitivity.

2.3.2 Solar PV forecasts

The difference between gross demand and GXP demand (which is primarily used in our analysis), is distribution losses and embedded generation. A part of the embedded generation is rooftop solar PV. We discussed the forecast uptake of solar PV in our panel meetings and decided to increase the uptake compared to EDGS 2019. For information and comparison, we show how our resultant NZGP1 solar PV forecasts compare with the original EDGS 2019 in Figure 5. The left plot shows the EDGS 2019 forecasts, and the right plot shows the variations that we consulted on along with the updated uptakes that we have used for NZGP1. The solid lines represent the NZGP1 forecast, and the dashed lines represent the EDGS 2019 variations.

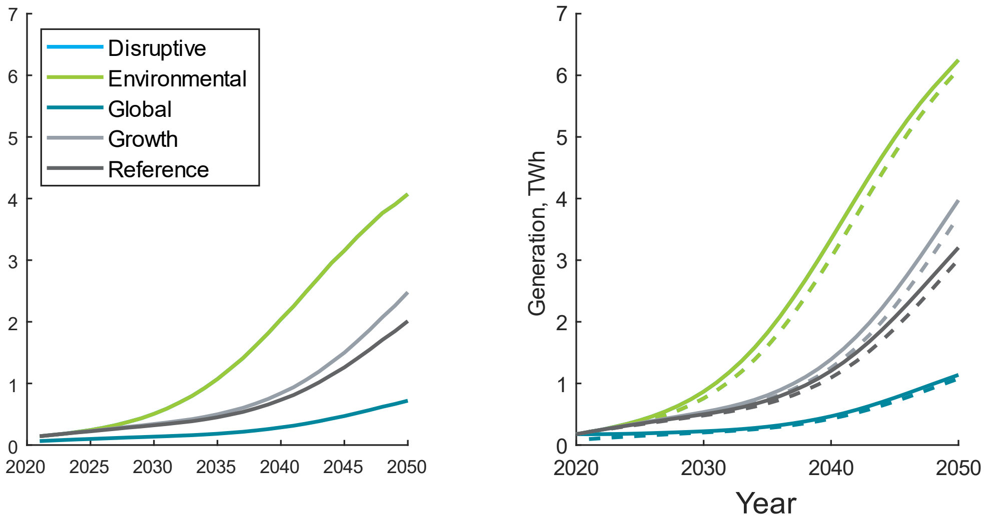

Figure 5: Solar demand for the three variations of the EDGS

2.4 NZGP1 generation scenario assumptions

2.4.1 Introduction

This section describes the generation scenario assumptions for NZGP1. These assumptions feed into the generation expansion plan (or forecast) modelling described in the next section.

NZGP1 generation assumptions were initially developed and consulted on as part of a package of variations to the 2019 EDGS. We incorporated significant changes to the environment in which generation investment decisions are likely to made since the EDGS 2019 was published. We included MBIE's update to their new generation stack (thermal, hydro, geothermal, wind and solar generation were all reviewed). This shows that generation costs have changed significantly, particularly so for wind and grid scale solar projects. We also include costs for batteries and updated costs for biofuels, two important alternative peaking and dry year reserve options. Our assumptions include updates of other critical cost drivers. Notably, we have revised greenhouse gas emission costs projections, such that they accord with the latest thinking in this area.

2.4.2 Grid scale solar assumptions

While the cost of both grid scale solar and wind are expected to drop significantly it is uncertain which technology is likely to be more dominant in the future. Grid-scale solar has several investment characteristics compared to grid-scale wind which might make it attractive to some investors. Solar projects have lower set-up costs (access roads, etc), can be built close to the existing transmission, are easier to find land for, are easier to consent and because of their smaller capital requirement, are easier to finance. In comparison, wind farms generally need to be larger to be economic. An approach where we simply use the same discount rate for both technologies does not necessarily reflect these issues or market expectations for future investment in grid scale solar in New Zealand.

To address the uncertain relative competitiveness of wind and solar we settled on a target MW ratio of grid-scale wind: solar build (on an installed MW capacity basis) between now and 2050 of 75% wind: 25% solar. To achieve this target, we adjusted the project discount rate for solar projects as used in our generation expansion plan modelling. **Error! Reference source not found.** describes t he discount rates for this proposal.

Table 2: Grid scale solar project discount rates

EDGS scenario	Grid scale solar discount rate
Reference	5%
Global	5%
Growth	4.5%
Environmental	5%
Disruptive	7%

The 2020 MBIE generation stack uses a set of potential 'hypothetical' projects based on such factors as the solar resource, availability of consentable land and distance from the transmission grid.

Recently there has been increased activity by potential solar generation developers, leading to numerous inquiries to connect solar generation projects to the transmission grid. Transpower's connection inquiry connection process provides quality information on the likely size and location of solar generation projects in New Zealand.

To take advantage of this information we have updated the 2020 MBIE solar generation stack as follows:

- Connection query projects that are likely to be developed have been added to the stack.
- To avoid duplication, if a project in the 2020 MBIE solar generation stack is similar (in terms of location and size) to a connection query project added to the stack then it has been deleted.

- 'Near term planned solar farms' as described in the transmission pricing methodology BBC Assumptions Book[6] have also been added to the stack.

A comparison of potential future solar projects in the original MBIE generation stack and the generation stack used for the application proposal is shown in Figure 4. This shows potential solar projects by region (see Figure 11) and information source. The bottom set of projects are from the 2020 MBIE generation stack, the middle set of projects are sourced from Transpower's connection queries and the top set of projects are those 'near term planned solar farms' projects used in the transmission pricing methodology.

Consistent with the BBC assumptions book, we have assumed all connection query solar projects are 'near term planned solar farms' with a capital cost of $1300/kW. This is at the lower end of the range of solar generation capital costs for the 2020 MBIE generation stack.

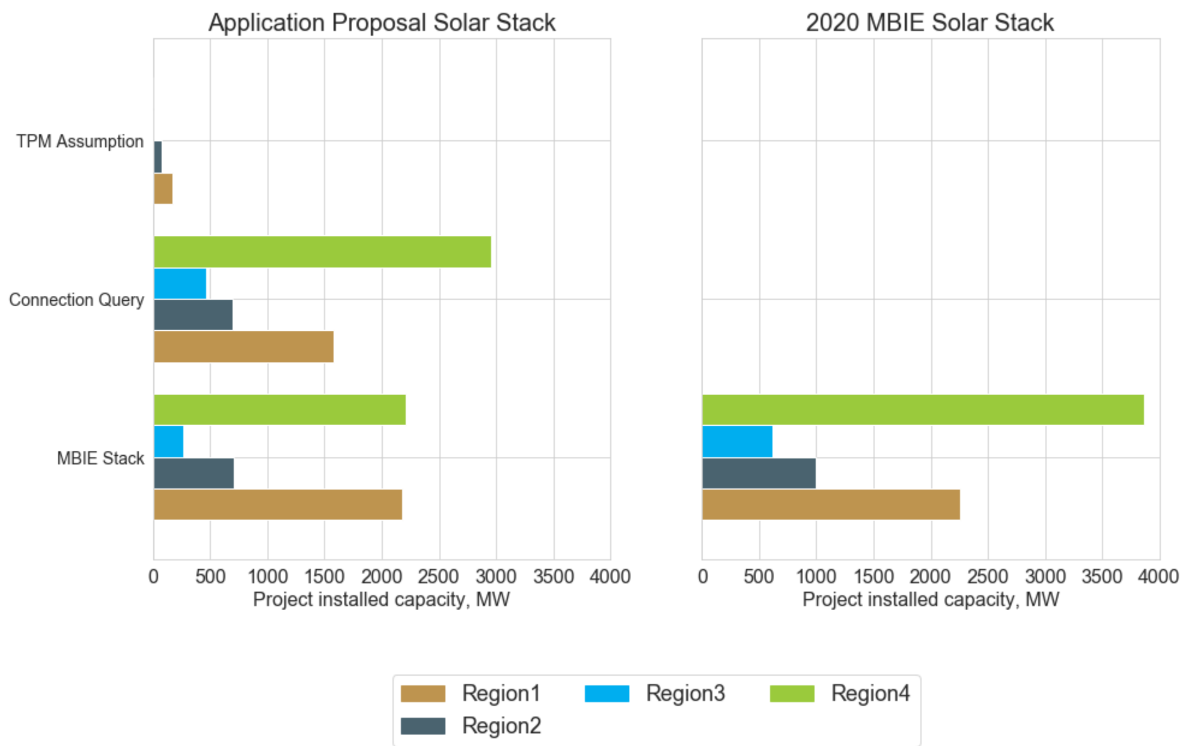

Figure 6: Solar generation stack, potential installed capacity, by region and information source

[6] See transmission pricing methodology BBC Assumptions Book, See transmission pricing methodology BBC Assumptions Book, paragraph 169.

2.4.3 Wind generation assumptions

Wind generation assumptions that vary from EDGS 2019 include:

Wairarapa wind generation

The EDGS wind generation stack includes significant (500 – 1000 MW) new wind generation in the Wairarapa. There are consented projects in the region which have not yet lapsed, but these projects do not appear to be of immediate interest to generation investors. Given the effect these projects would have on generation development, should they proceed, we have not discarded them, but they are flagged on the generation stack with a 'not before 2035' flag.

Repowered wind

Wind generation plant is assumed to have a 30-year life in our model and approximately 670 MW of existing wind generation reaches the end of its life during the period 2030 – 2050. Based on consultation feedback, we have re-powered these sites, rather than assume those plants are totally decommissioned. In our modelling, we have assumed that all existing windfarms are re-powered once the existing generation reaches end-of-life and that the re-powered site will have approximately 2.1 times the capacity it had previously.

2.4.4 Geothermal generation assumptions

During consultation on our EDGS variations it become clear that the raw geothermal generation costs provided in MBIE's new generation stack do not result in the future development of this technology consistent with market expectations. Consultation feedback highlighted factors that additional factors should be taken into account when considering the economic potential for geothermal generation:

a. Geothermal generation has a lifetime of 60 years compared to wind and solar which are 30 years. This affects the annualised cost included in the generation expansion model.
b. Investigations are ongoing as to uses for the geothermal steam after it has been used for electricity generation. At that stage it is still hot and could be used for other processes. No such value is allowed for in the capital costs include in the generation stack but would effectively reduce the initial capital cost of the project.
c. Investigations are ongoing regarding re-injecting the steam after use, or otherwise stripping the CO2 out – both approaches would reduce the effective CO2 emissions to nearly zero. Given we are valuing CO2 emission at $250 per tonne CO2 e by 2050, this would be significant
d. One project has received a government subsidy. This effectively reduces the capital cost for that project, yet that is not reflected on our generation stack.

To take account of these factors, we have modified the capital cost of geothermal in the generation stack (by 50%) and reduced CO2 emissions by 80%.

2.4.5 Fossil fuel generation assumptions

Fossil fuel retirements are aligned with MBIE's thermal generation stack. Notably:

- Taranaki Combined Cycle (TCC) retires in 2025.
- Huntly's Rankine units (1, 2 and 4) are assumed to retire at Genesis' intended end date of coal fuelling in 2030.
- Huntly's combined cycle unit (E3p or Huntly Unit 5) retires in 2037.

The existing fossil fleet, together with anticipated retirements, is shown in Figure 7.

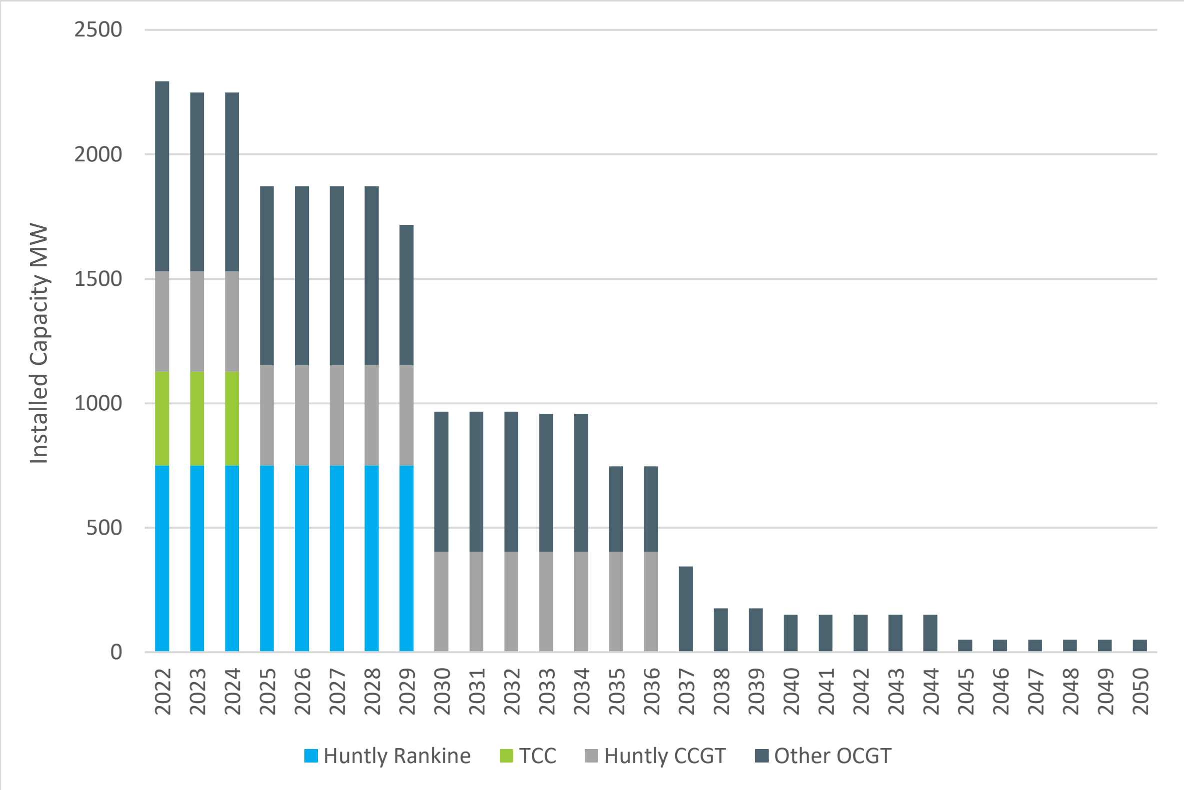

Figure 7: Existing fossil fuel fleet installed capacity, with retirements

2.4.6 Peaking and dry year solutions

Grid scale batteries

Grid scale batteries have been added to the MBIE generation stack using information data from the 2021 Annual Technology Baseline produced by NREL. This provides a consistent set of technology cost and performance data for energy analysis.

The battery projects that we have modelled are capable of either four or eight hours' worth of storage. This means that these projects will primarily provide short term support to the electricity system when demand is high, or supply is short. They will not be able to support the electricity system for extended periods of time as would be required, for example, during a dry year.

In our modelling battery revenues do not take account of any potential revenue from offering instantaneous reserves or transmission support services. Batteries will have the same incentives to locate in high priced regions of the electricity system (which may be upstream of a transmission constraint) as any other form of generation that is coupled to a particular location.

Grid scale batteries will partly compete with other peaking solutions including demand response and biofuels. These other alternatives have an advantage in that they may also be able to support the electricity during extended supply shortages, including dry years or weeks when solar or wind generation is below average. To ensure a reasonable balance between grid scale batteries and other peaking solutions we adjusted the project discount rate for grid scale batteries for our Disruptive scenario. The project discount rate was increased from 7% to 8% for this scenario.

Biofuels

All scenarios include the option to build a biofuels 'peaking' plant (up to a maximum capacity of 1500 MW), that can provide both peaking and dry year support. We conservatively place this project in Huntly such that it is unlikely to influence the transmission issues considered in this application proposal. The biofuels peaking project can be built from 2035 from all scenarios except for the environmental scenario. For this later scenario, consistent with its much higher greenhouse gas emissions cost, we assume that biofuels peaking project can be built from 2030 onwards.

Biofuels project capital and operating costs are provided in **Error! Reference source not found.**. T hese cost result in relatively high-cost generation, with a short-run marginal cost of $305/MWh.

Table 3: Biofuel peaking plant cost assumptions

Cost element	Cost
Capital cost ($/kW)	1030
Fixed operating costs ($/kW-year)	4.6
Fuel cost ($/GJ)	25
Heat rate (GJ/MWh)	11.75
Variable operating costs ($/MWh)	11.4

Demand response

We model demand response as both a peaking and dry year solution. Demand response could potentially be sourced from control of residential hot water cylinders through to planned load shedding from large industrial facilities. This demand response is available at the levels described in **Error! Reference source not found.**.

Table 4: Demand response costs

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

2.4.7 Generation stack costs and future cost declines

Generation stack costs are sourced from the MBIE generation stack update published in 2020[7].

We have used NREL's 2021 Annual Technology Baseline[8] for future declines in capital cost across all technologies. While MBIE's generation stack also includes information on future capital cost declines we have used the NREL analysis as is based on consistent assumptions across technologies and should not introduce a technology bias. NREL are also the only source of data for grid scale batteries.

Table 5 shows the capital cost declines for each EDGS scenario. We used the conservative cost decline trajectory for wind technology in the Disruptive scenario. This was done to create a scenario with a heavier bias toward solar technology. This was required because, as the cost stack numbers stand, wind technology was generally preferred within our least-cost expansion model due to higher capacity factors and lower overall costs.

[7] MBIE New Zealand generation cost update
[8] NREL's 2021 Annual Technology Baseline

Table 5: Capital cost declines by scenario

	Grid scale batteries	Grid scale solar	Wind	Geothermal
Global	Conservative	Conservative	Conservative	Conservative
Reference	Moderate	Moderate	Moderate	Moderate
Growth	Moderate	Moderate	Moderate	Moderate
Environmental	Moderate	Moderate	Moderate	Moderate
Disruptive	Advanced	Advanced	Conservative	Advanced

2.4.8 Other important variations to the EDGS

Natural gas price projections

We have used the Climate Change Commission (CCC) gas price as reflected in their "All other CCC scenarios" assumption (included in their Emissions Budgets advice to government recently), in our modelling. This equates to the gas price assumptions in **Error! Reference source not found.** (for f urther detail see section 4.2.1).

Table 6: Gas price assumptions

	2030	2040	2050
Gas price, $/GJ	6.7	6.9	7.8

Greenhouse gas emission price projections

Similarly, we have used the CCC greenhouse gas emission costs from their recent Emissions Budget advice to government, for all EDGS scenarios except for the environmental scenario. In their advice, the CCC outline carbon abatement costs that would be required to eliminate fossil-fuel emissions from those sectors where there are low-emissions alternatives, and they use these costs in their analysis.

For the environmental scenario we use the moderately more aggressive greenhouse gas emission costs projections from the IEA's 2021 World Energy Outlook. Specifically, we use carbon prices for the Net Zero Scenario and for 'advanced economies[9].

[9] IEA's 2021 World Energy Outlook

NZGP1 greenhouse gas emission costs are shown in Figure 8 (for further detail see section 4.2.2).

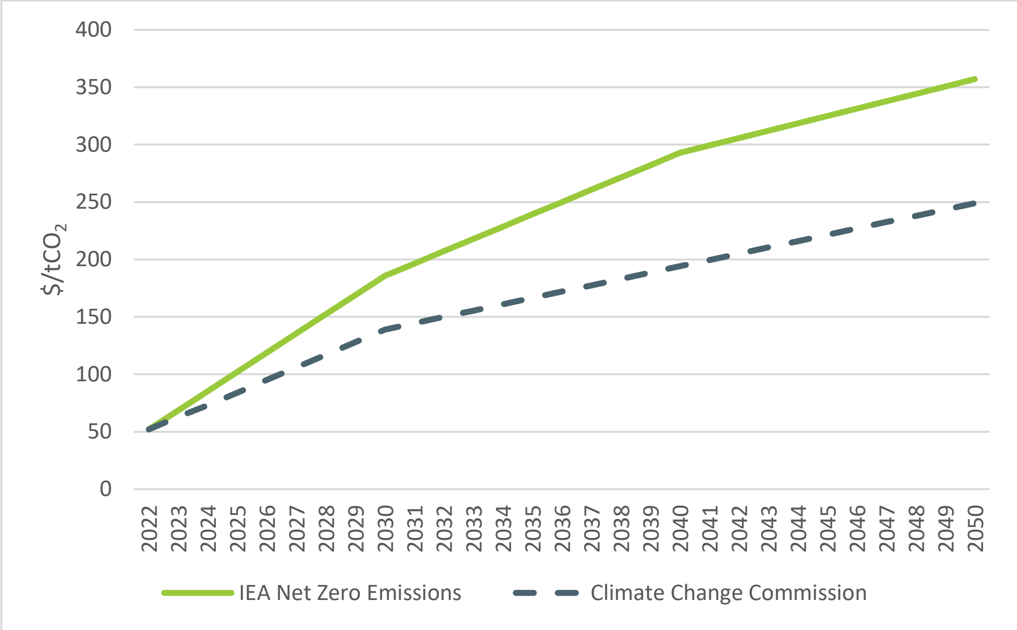

Figure 8: Greenhouse gas emission cost projections as used in NZGP1

2.5 Transmission pricing methodology assumption variations

NZGP1's assumptions are closely aligned to those developed for the transmission pricing methodology (TPM) to support the allocation and adjustment of transmission benefit-based charges (BBC). These TPM assumptions are described in detail in the BBC Assumptions Book[10].

There are some areas where the NZGP1 assumptions and TPM assumptions differ and these are detailed, together with a rationale for the difference, in section 4.0.

[10] BBC Assumptions Book.

3.0 Modelling

3.1 Modelling Approach

3.1.1 Introduction

Transpower uses models of the New Zealand electricity system to estimate the relative benefits of alternative transmission options.

An overview of our modelling approach is shown in Figure 9. Our system planners will first identify issues on the transmission grid and identify a list of possible transmission investment options. From there, for each option, we follow a two-step modelling process:

- We first find the lowest cost combination of generation projects that must be built to meet forecast demand over the modelling horizon (from 2022 through to 2055). This is our generation forecast or 'generation expansion plan' and is developed using PSR Inc's OptGen software. Generation expansion plans must be developed for each EDGS scenario.
- We next work out the quantity of generation that should be dispatched to minimise electricity system costs for each year in the modelling horizon. This dispatch solution allows us to calculate electricity system operating costs. This step is performed for a range of hydro inflow scenarios and for each of our generation expansion plans. Least cost generation dispatch is produced using PSR Inc's SDDP software.

This two-step modelling process is repeated for a 'factual' case and 'counterfactual' case. The proposed transmission option is included in the factual case modelling and excluded from the counterfactual case modelling. The counterfactual is our do-nothing option. The relative benefits of a transmission option are given as the difference between factual and counterfactual system costs.

The preferred transmission option will be determined by an assessment of the relative benefits of each transmission option.

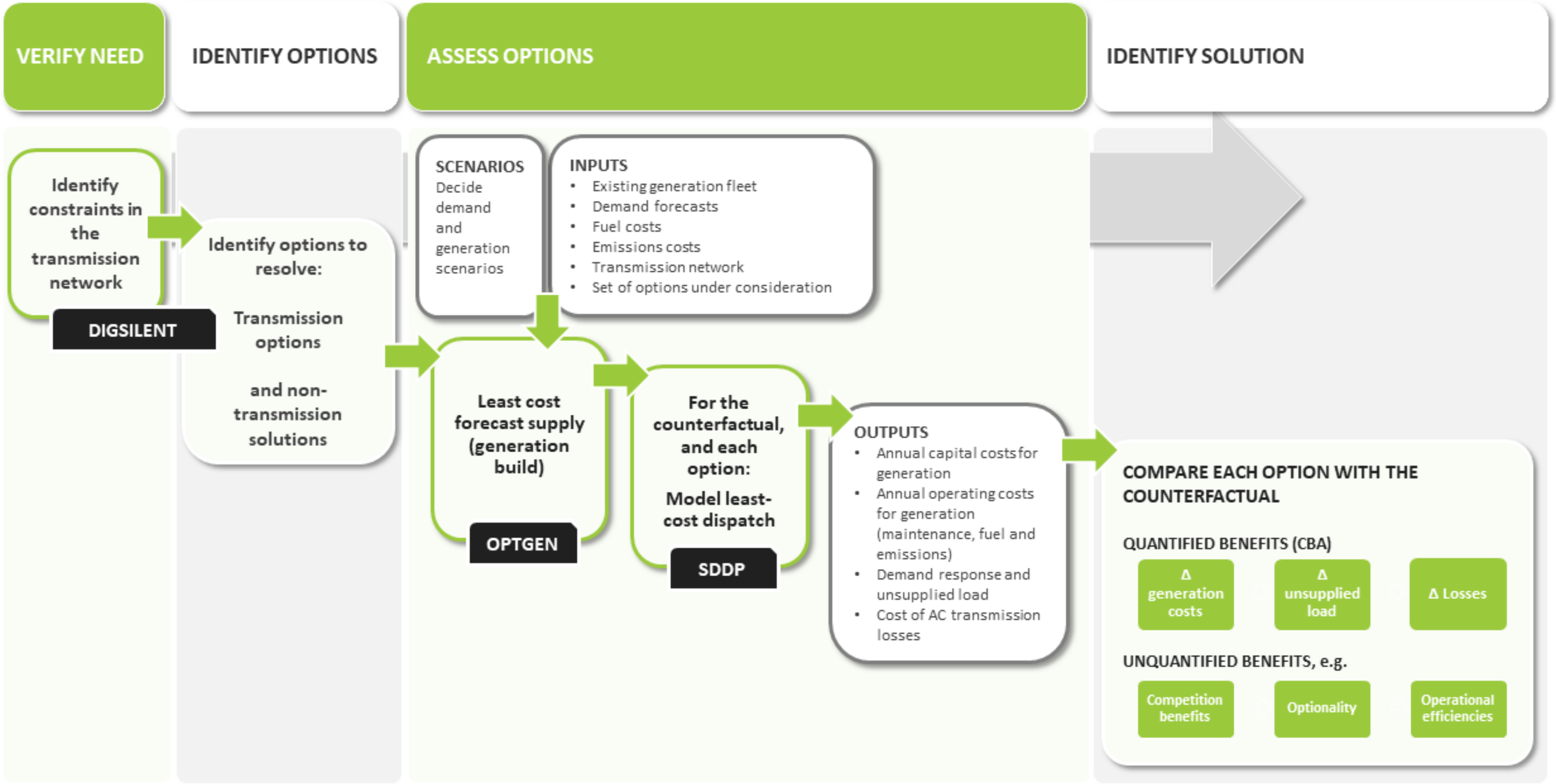

Figure 9: Overview of our modelling methodology

3.1.2 Generation expansion plan modelling

Least cost generation expansion plans

Generation investors take a lot of things into account in making their investment decisions – generation cost, availability of capital, their future view of wholesale electricity prices, consentability of their projects, perhaps their likelihood to agree a power purchase agreement if they are a generation company only, perhaps how new generation balances their retail portfolio if they are a generator/retailer – and all of those issues depend upon their company strategy, which could be to be long, short or balanced in the wholesale market.

Generation cost is the only one of these considerations included in our least-cost generation expansion modelling. Our modelling effectively steps through time (out to 2055 in this case), building new generation as required to meet forecast demand. It chooses new generation from the generation stack and its overall objective is to minimise the cost of electricity over the period being considered. The model effectively ignores market behaviour and other investment decision-making factors discussed above. In our view this is reasonable, on the premise that, although our model may deliver new generation in a different order to the actual electricity market, in the long-run, electricity cost will be the major deciding factor and so the set of projects identified by our generation expansion will be pertinent

Using OptGen

PSR Inc's OptGen modelling software has been used to develop our generation expansion plans. We use the 'Optgen2' algorithm. This algorithm finds the lowest cost combination of capital costs (due to investments in new generation) and operating costs (due to operating existing and new generation plant) for each year in the modelling horizon. The algorithm is a 'rolling horizon scheme', such that investment decisions made in previously modelled years are fixed.

The Optgen2 algorithm handles hydro inflow variability by taking a 'multi-deterministic' approach. This means costs are optimised for multiple hydro inflow sequences and that hydro generation operating decisions are made assuming future inflows are 'known' by the model. While this approach does not necessarily represent real world hydro generation operation it does limit the computational effort required to generate each generation expansion plan.

The Optgen2 algorithm also uses a small number of 'typical days' to model hourly variations in demand and intermittent renewable generation. While this is another simplification, a full hourly representation would be overly cumbersome.

Optgen2 can be configured with several different possible generation energy or capacity constraints. We have applied a 'firm capacity constraint' to ensure that the model builds sufficient firming capacity to support intermittent renewable generation.

How many generation expansion plans?

We produced generation expansion plans for each combination of EDGS scenario and HVDC option (including the counterfactual). We found that we did not need to alter our generation expansion plans to account for different AC transmission options. To investigate this issue, for a sample EDGS scenario and HVDC option, we produced generation expansion plans with:

- The existing AC grid for both the CNI transmission corridor and Wairakei ring added to the model.
- An unconstrained AC grid for the same areas of interest added to the model.

These generation plans were very similar. The minor differences found were confined to the late in the modelling horizon.

3.1.3 Generation dispatch modelling

PSR Inc's SDDP modelling software has been used for generation dispatch modelling. The SDDP algorithm minimises system operating costs over the modelled horizon with hydro generation operating decisions based on future hydro inflows that are variable, uncertain and (from the perspective of the model) unknown.

Model resolution

The process of choosing the best resolution for a model is a compromise between model accuracy and computational tractability. For SDDP, resolution relates to the size of the time step considered by the model. Resolution is improved by reducing the size of the time step. A model with a high resolution will better capture real world variations in demand and intermittent generation. This will, though, be at the expense of increasing model solve time and model result data storage requirements. Model resolution has become much more important as it is now anticipated that a much greater proportion of our future generation needs will be met by intermittent renewable generation.

SDDP can model the electricity system either at an hourly resolution or at a resolution set by a user defined group of 'load blocks'. A load block has a fixed load and duration. A group of load blocks, taken together, can simulate a load profile for a given increment of time. In SDDP this increment of time can be selected to be either weekly or monthly. Model resolution can be improved by either increasing the number of load blocks or by simulating a load profile that covers a shorter increment of time. A SDDP case with load blocks will always have a lower model resolution than an SDDP case set to an hourly resolution.

Modelled benefits for NZGP1 have been estimated using a combination of modelling results from:

- Yearly 'snapshot' SDDP cases using an hourly resolution. Snapshots are taken once every five years over the full modelling horizon.

- SDDP cases where demand has been aggregated into weekly, twenty-one load blocks over the full modelled horizon.

Where possible benefits have used yearly snapshot results at an hourly resolution. For intervening years with no yearly snapshot results, benefits are derived by multiplying load block benefits by an 'hourly resolution' factor. This hourly resolution factor is calculated by first calculating the ratio of hourly to load block benefits for each yearly snapshot year. The hourly resolution factor is then given by the interpolating the ratio of hourly to load block benefits for each intervening year.

Instantaneous reserves

Instantaneous reserves are reserves of generation or 'interruptible load' that ensure system frequency remains in acceptable limits if there are unexpected generation or HVDC outages on the system.

Our generation dispatch modelling has ignored the costs of instantaneous reserves for these reasons:

- Adding reserves into SDDP increases model solve time.
- Reserve costs are difficult to estimate in the medium to long term. Over this time frame there are likely to be new source of instantaneous reserve, including from batteries, demand response and biofuel peakers. The costs of these new sources of reserve are unclear.
- It is possible that some of the proposed HVDC options may reduce instantaneous reserve procurement costs where the HVDC sets the risk in the North Island. The HVDC though currently only sets the risk in the North Island for a relatively small fraction of time.

Policies, simulations and hydro sequences

SDDP generation dispatch results are produced in two steps:

1. Policy step. In this step SDDP derives a hydro generation policy, effectively a set of water storage values. Water storage values can be regarded as providing the opportunity cost of using or storing water in a hydro reservoir.
2. Simulation step. Using the water storage values from the policy step the operation of electricity system is simulated for a given set of hydro inflow sequences.

Within the policy step, we use synthetic hydro inflow sequences that are derived from actual inflows. Synthetic inflows reduce the level of fluctuations, help the model converge, and reduce model solve time. They are produced by SDDP by analysing the relationship between an inflow sequence and time of year as well as the interdependence among inflows to different hydro plants. For NZGP1 we use 50 synthetic inflows for the policy step, which is a practical trade-off between precision and model solve time.

For our weekly, twenty-one load block SDDP case simulations, we use the actual historical inflow sequences. We run the simulation across all available hydro inflow sequences. For our yearly, hourly resolution, snapshot SDDP case simulations we fall back to using 50 synthetic inflows as another practical trade-off between precision and model solve time.

How many policies?

SDDP hydro generation policies need only be produced where changes are made to SDDP inputs that could materially alter hydro generation operating decisions and associated water storage values. For NZGP1, consistent with our generation expansion plan approach, we ran hydro generation policies for each combination of EDGS scenario and HVDC option (including the counter factual). Varying either of these parameters could potentially have substantial impacts on the expected value of water. For a given EDGS scenario and HVDC option combination we applied the same hydro generation policy to all associated AC transmission options. In our view the proposed AC transmission options are unlikely to affect the expected value of water. This allowed a significant reduction in modelling complexity and overall solve time.

3.1.4 Modelling the grid

HVDC

The HVDC (and enhancements) are included in our generation expansion and generation dispatch modelling. Both models account for energy losses across the HVDC in their respective cost optimisation processes.

AC grid

A simplified representation of the AC grid is also included in our generation expansion and generation dispatch modelling. Key aspect of our AC grid model include:

- Only circuits above 66kV are included.
- Losses are not considered when determining either our least cost generation expansion plans or generation dispatch. Losses are estimated, as a post processing step (after the model has been run), based on dispatch circuit flows, when estimating benefits.
- Circuit constraints are only considered for those areas of the grid relevant to the application proposal. Circuit constraints include thermal limits and pre-contingent overload limits.

3.2 Generation expansion plans

3.2.1 Generation expansion plans for each scenario

Generation expansion plans for each scenario are shown in Figure 10. These expansion plans assume Tiwai leaves in 2024 and that a fourth HVDC cable is installed by 2027. Figure 9 shows new installed generation capacity in MW. Plant retirements are not shown, and we only include the net additional installed capacity for wind farm repowering projects.

We observe:

- All scenarios build a significant quantity of biofuels in the 2030s. This aligns with the retirement of the fossil fuelled Huntly power station Rankine units in 2030 and combined cycle unit in 2037. By 2050, the Disruptive scenario builds 500MW of biofuel plant, half as much as the other EDGS scenarios.
- All scenarios build grid scale batteries. The Disruptive scenario builds the most, with 1250 MW of installed capacity by 2050.
- Aside from biofuels and grid scale batteries, the bulk of new generation capacity is made up of geothermal, wind and solar. There is a relatively wide variation between the scenarios. For example, the Global scenario builds no grid scale solar generation, while the Disruptive scenario builds 2700 MW of grid scale solar.

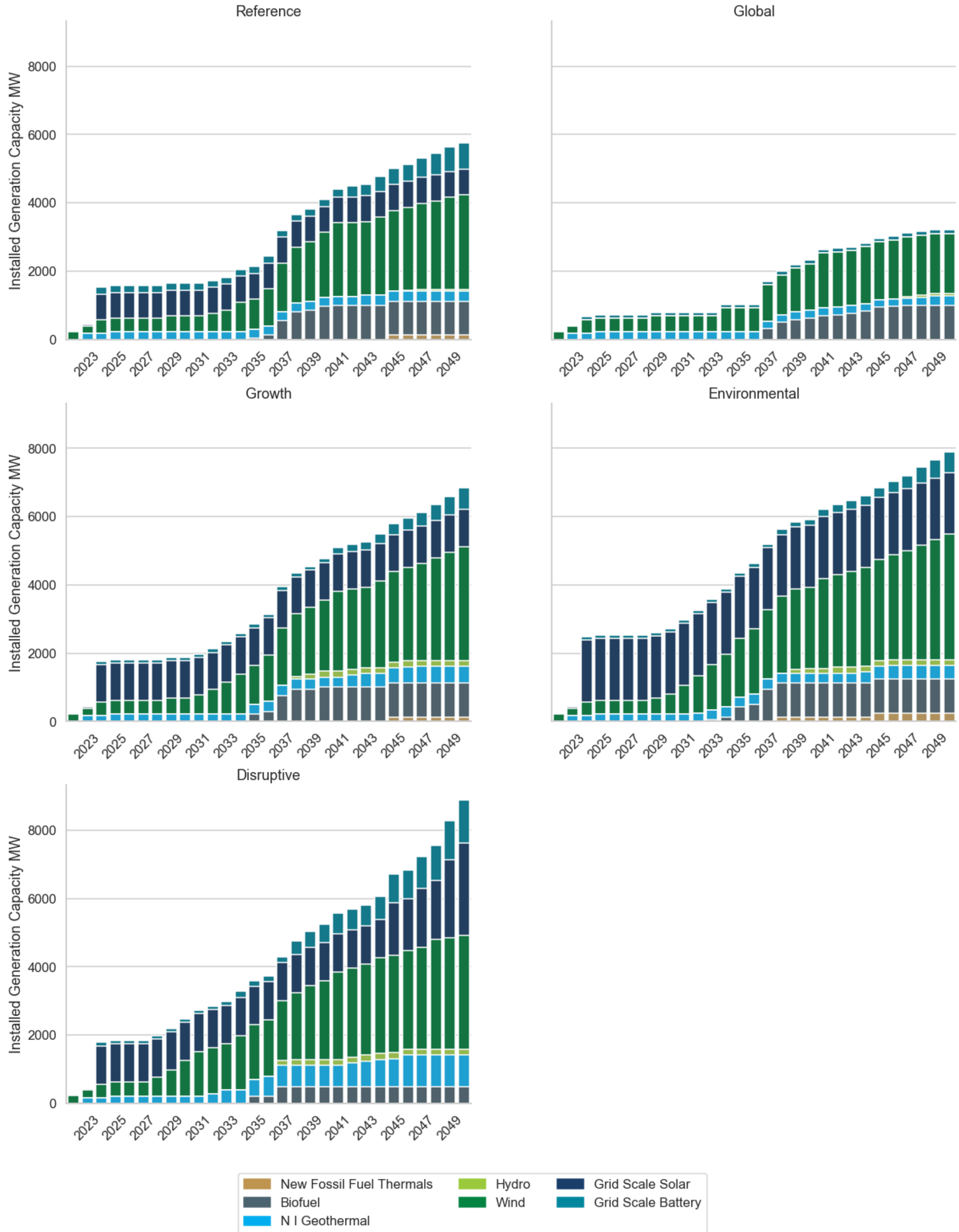

Figure 10: New installed generation capacity for each scenario

3.2.2 Generation expansion plans each region

When considering our generation expansion plans in our view it useful to divide New Zealand into four distinct regions as described in Figure 11.

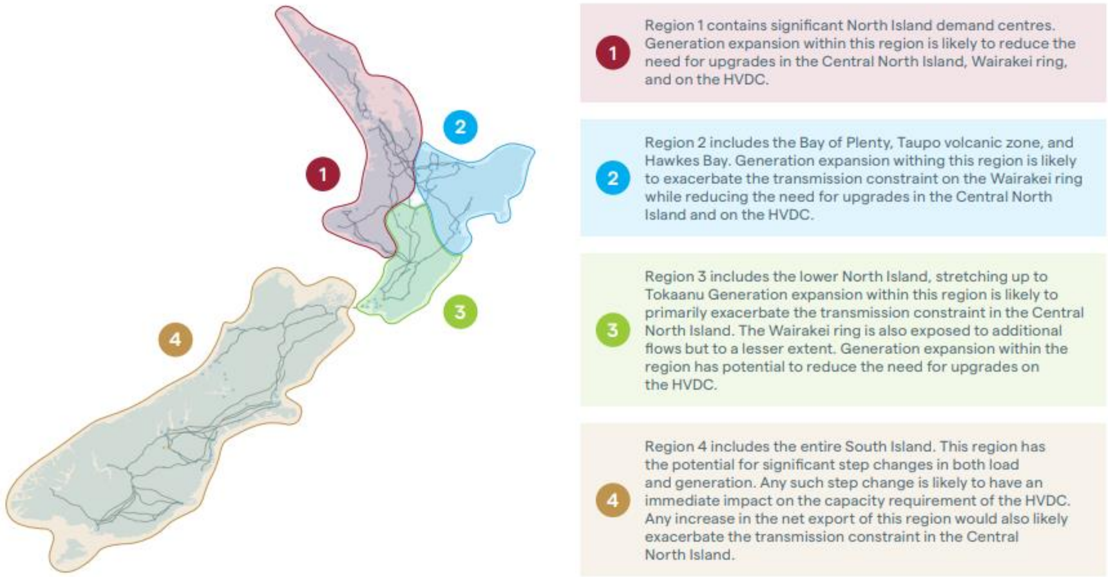

Figure 11: Regions relevant to our NZGP1 investigation, in terms of new generation

Generation expansion plans for each region as of 2050 are shown in Figure 12. Expansion plans assume Tiwai leaves in 2024 and that a fourth HVDC cable is installed in 2027.

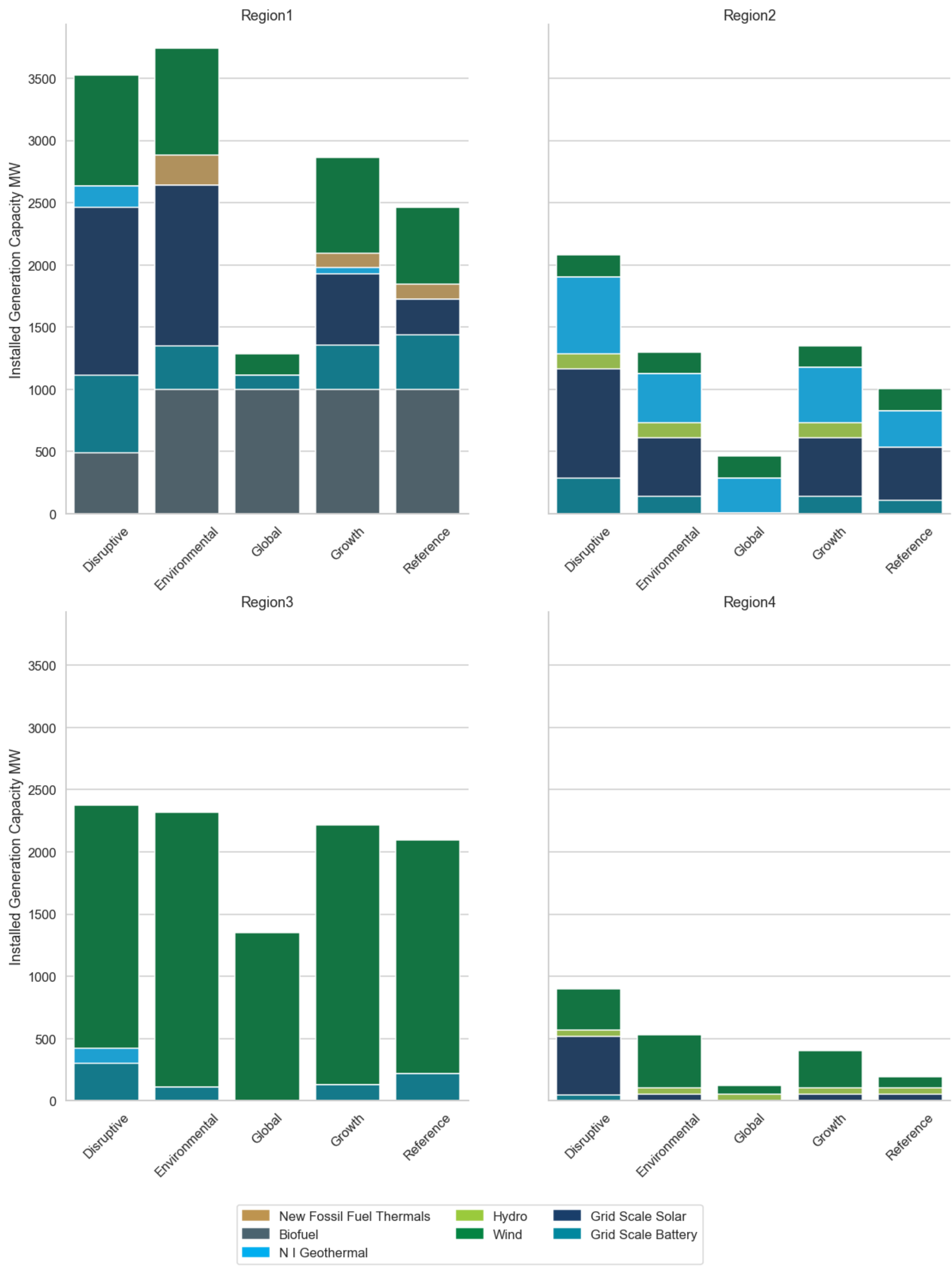

Figure 12: New installed generation capacity by region in 2050 for each scenario

We observe:

- While new wind generation is built in all our four regions, the majority is built in the Region 3.
- Grid scale solar generation is built, for the most part, in regions 1 and 2. The Disruptive scenario is the only scenario with grid scale solar built in the South Island.
- There a reasonable diversity of generation build across the EDGS scenarios to adequately test the proposed transmission investments.

3.2.3 Generation expansion plans comparison with EDGS

A comparison of generation expansion plans with EDGS is shown in **Error! Reference source not found.**.

Table 7: Comparison of EDGS and NZGP1 Generation Expansion Plans

	EDGS Scenarios					NZGP1 Scenario Generation Expansion Plans				
Technology, 2050 Installed Capacity, MW	Reference	Global	Growth	Environ-mental	Disruptive	Reference	Global	Growth	Environ-mental	Disruptive
Fossil Fuels	900	800	1,400	1,100	1,300	120	0	120	240	0
Hydro	400	800	1,100	1,100	1,400	50	50	170	170	170
Geothermal	1,100	600	1,400	1,400	1,700	290	280	490	390	910
Wind (gross repowered capacity)	3,400	1,300	4,100	4,500	4,700	3,420	2,420	3,990	4,330	4,000
Grid Scale Solar	-	-	-	-	-	760	0	1,090	1,810	2,690
Grid Scale Batteries	-	-	-	-	-	760	120	620	590	1,250
Biofuels	500	300	1,400	1,500	1,500	990	990	990	1,000	490
Total	6,300	3,800	9,400	9,600	10,600	6,390	3,860	7,470	8,530	9,510

3.2.4 Generation expansion plans HVDC investment impacts

The generation expansion plans presented above assume that a fourth HVDC cable is installed by 2027. Figure 13 shows how the generation expansion plans change if there are no upgrades to HVDC capacity. To do this we compare new installed generation capacity, as of 2050, with and without the HVDC fourth Cable. In this chart, a *positive* installed capacity difference for a generation technology means that more of that technology is built with the fourth HVDC Cable. For example, for the Disruptive scenario, there is 100MW of additional Biofuel capacity built by 2050 *with* the fourth HVDC Cable.

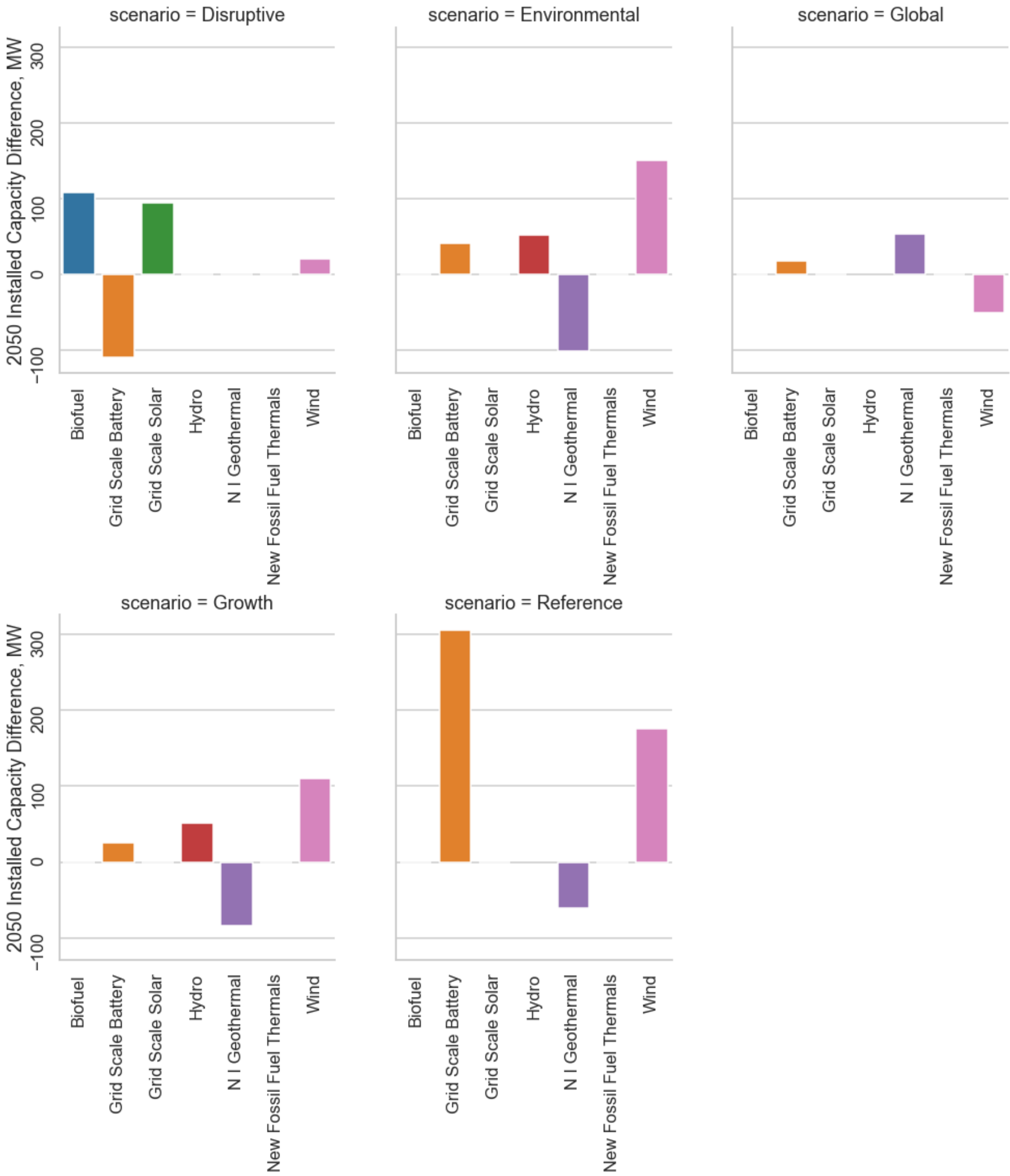

Figure 13: Generation expansion plans, as of 2050, with and without a fourth HVDC cable

We observe:

- Differences between generation expansion plans with and without the HVDC fourth cable are relatively small.
- The Reference, Environmental and Growth scenarios have more (100 - 200 MW) new wind generation and less geothermal generation (50 – 100 MW) with the HVDC fourth cable.

3.2.5 Generation expansion plans if Tiwai leaves in 2034

Figure 14 shows how generation expansion plans change if Tiwai leaves in 2034 and the Fourth Cable is installed at the same time (rather than 2027). A *positive* installed capacity difference for a generation technology means that more of that technology is built if Tiwai leaves in 2024. Across all scenarios the changes in installed generation are relatively small.

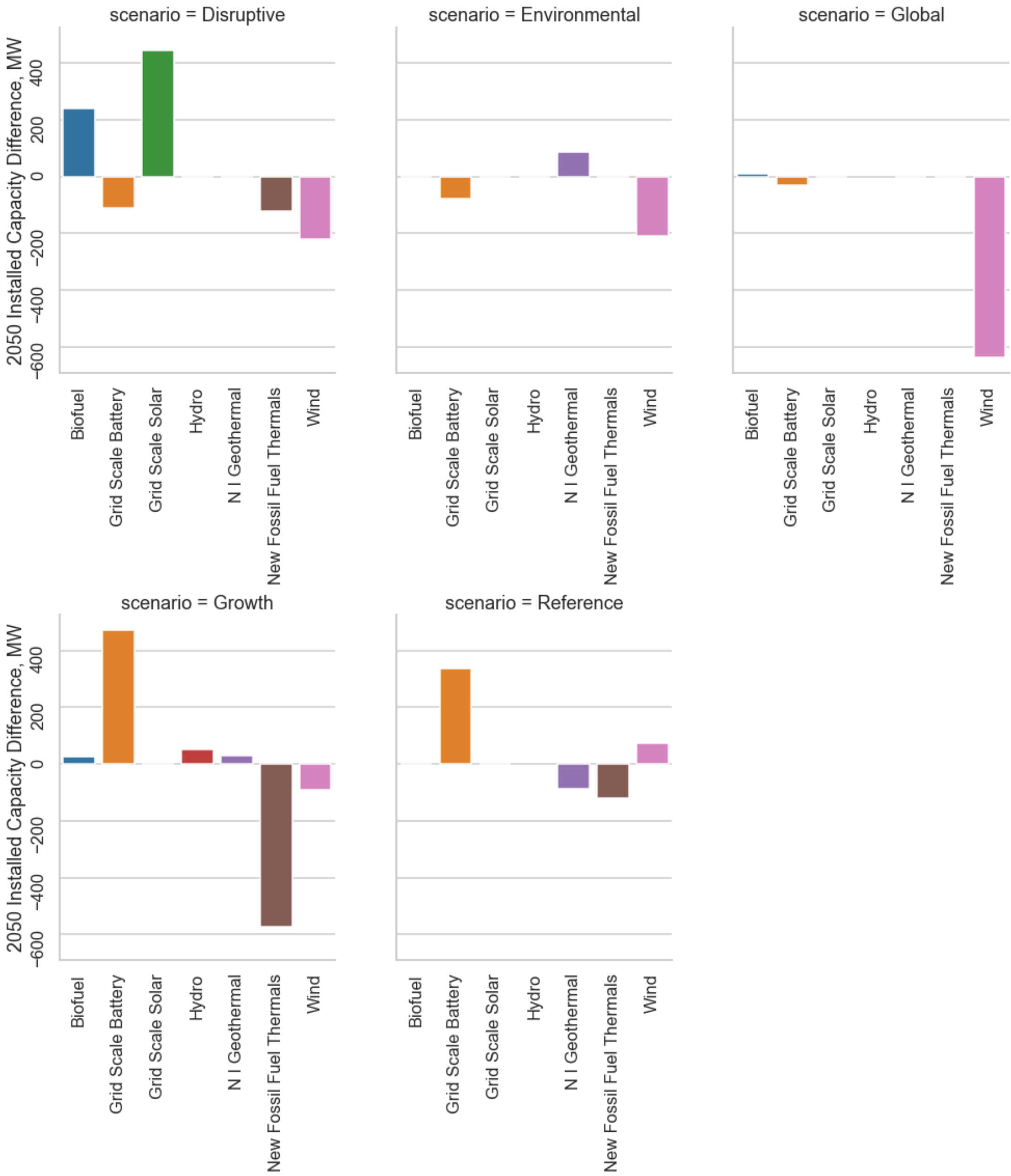

Figure 14: Generation expansion plans, as of 2050, Tiwai leaves in 2034 vs. Tiwai leaves in 2024

3.3 Investment test gross benefits

3.3.1 Introduction

This section presents investment test gross benefits. These are the estimated gross benefits of each proposed transmission investment across all EDGS scenarios. Benefits are derived by estimating electricity system costs with (the 'factual') and without (the 'counterfactual') the transmission investment. This process is repeated across all scenarios.

3.3.2 Benefit categories

We have considered the following benefit categories

Capital and fixed costs

Capital and fixed costs are costs associated with new generation investments. Differences between the factual and counterfactual for this cost category will flow directly from differences in generation expansion plans. For a given EDGS scenario and HVDC option we have used the same generation expansion plan for each AC grid investment option (see section 3.1.2). This means, for a given EDGS scenario and HVDC option, capital and fixed costs will stay the same for different AC grid investment options.

Thermal operating costs

Thermal operating costs include variable operating costs associated with running thermal generation. This will made up of fuel costs and a small proportion of variable maintenance costs. Thermal generation includes fossil, geothermal and biofuels generation.

Differences between the factual and counterfactual for this cost category will flow from differences in both generation expansion plans and generation dispatch. Thermal operating costs could be reduced, for example, if:

- A transmission constraint in the counterfactual is relieved in the factual such that less costly, non-thermal generation is dispatched, displacing thermal generation.
- If the installed capacity of non-thermal generation is greater in the factual than the counterfactual.
- If the installed capacity of thermal generation is less in the factual than the counterfactual.

Emission costs

Emission cost differences between the factual and counterfactual will flow directly from changes in emissions intensive generation dispatch and will correlate closely to thermal operating cost differences.

Deficit costs

Deficit costs relate to the cost of curtailed demand using the deficit cost tranches described in Section 2.4. Deficit cost differences between the factual and counterfactual will flow directly from differences in both installed generation and generation dispatch. Either of these differences could increase or decrease energy supply to a supply constrained region of the grid.

AC Loss Costs

AC loss cost differences flow from differences in energy flows across the AC grid. AC loss costs are not considered when producing least cost expansion plans or generation dispatch. Because of this they must be calculated in a separate post processing step. AC loss costs are given as the product of AC losses and short run marginal costs:

- AC losses are determined using known circuit resistance and circuit flow as derived from our dispatch model.
- Short run marginal costs are produced from our dispatch model. We cap short run marginal costs so that loss cost benefits are driven more by differences in energy flows, and less by modelled short run marginal costs[11].

AC loss costs are calculated across all 110kV and 220 kV circuits between BPE and OTA.

3.3.3 The counterfactual

For each transmission option gross benefits are estimated by finding the difference in the above costs between the counterfactual and factual. This is repeated for each of the cost categories discussed above. The counterfactual for each option always:

- Excludes the proposed transmission option upgrades.
- Assumes an HVDC north flow capacity of 1071 MW, reflecting current operating constraints on the HVDC[12].

3.3.4 Gross Benefits: CNI AC transmission intermediate options

We first present estimated gross benefits for CNI AC transmission intermediate options. For all options we assume:

- Tiwai leaves in 2024.
- HVDC upgrades include a statcom installed in 2026 and a fourth cable installed in 2027.
- Constraints on the Wairakei Ring are ignored.

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[11] To do this we first calculate an 'average short run marginal cost (average SRMC)' given as the loss cost (with no cap) divided by energy losses (across all circuits). The counterfactual average SRMC is capped at 120 $/MWh. The factual average SRMC is capped at between 100 – 120 $/MWh, such that the ratio of the factual to counterfactual average SRMC does not exceed 100 / 120.

[12] Refer to paragraphs 46-48 of the TPM BBC Assumptions Book v1.0.

We have investigated these 'intermediate' transmission options to confirm our selection of CNI transmission options for the grid investment test.

Table 8: Central North Island AC Transmission Options

Option Number	Option Name	Description
	All options	All options include the facilitating projects discussed in Attachment C.
C1	TTU TKU-WKM	Thermal upgrade (TTU) the TKU-WKM circuits, installed Dec 2023.
C2	TTU BPE-TKU + TTU TKU-WKM	TTU the TKU-WKM circuits, installed Dec 2023. TTU on the BPE-TKU circuits, installed Dec 2025.
C4	TTU BPE-TKU + TTU TKU-WKM + TTU BPE-WRK	TTU the TKU-WKM circuits, installed Dec 2023. TTU the BPE-TKU circuits, installed Dec 2025. TTU the BPE-WRK circuits, installed Sep 2027.
C5	TTU TKU-WKM + DUPLEX TKU-WKM	TTU the TKU-WKM circuits, installed Dec 2023. Duplex the TKU -WKM circuits, installed June 2026.
C6	TTU BPE-TKU + TTU TKU-WKM + DUPLEX TKU-WKM	TTU the TKU-WKM circuits, installed Dec 2023. TTU the BPE-TKU circuits, installed Dec 2025. Duplex the TKU -WKM circuits, installed June 2027.
C8	TTU BPE-TKU + TTU TKU-WKM + TTU BPE-WRK + DUPLEX BPE-TKU + DUPLEX TKU-WKM	TTU the TKU -WKM circuits, installed Dec 2023. TTU the BPE-TKU circuits, installed Dec 2025. Duplex the TKU -WKM circuits, installed June 2027. Duplex the TKU -WKM circuits, installed Feb 2030. TTU the BPE-WRK circuits, installed Nov 2031.

The gross benefits for each option are shown in Figure 15, broken down into each cost category. For a given scenario, there are only moderate variations in gross benefits across the modelled AC grid transmission options. Gross benefits increase as the scope of the upgrades increases, and this difference mostly corresponds to changes in AC loss benefits. The share of benefits by cost category varies substantially across the scenarios. Gross benefits for the Disruptive scenario include a large share of deficit cost reductions, whereas gross benefits for the Global scenario include a large share of thermal operating cost reductions. Capital and fixed cost reductions are either not present or a relatively small share for all modelled scenarios.

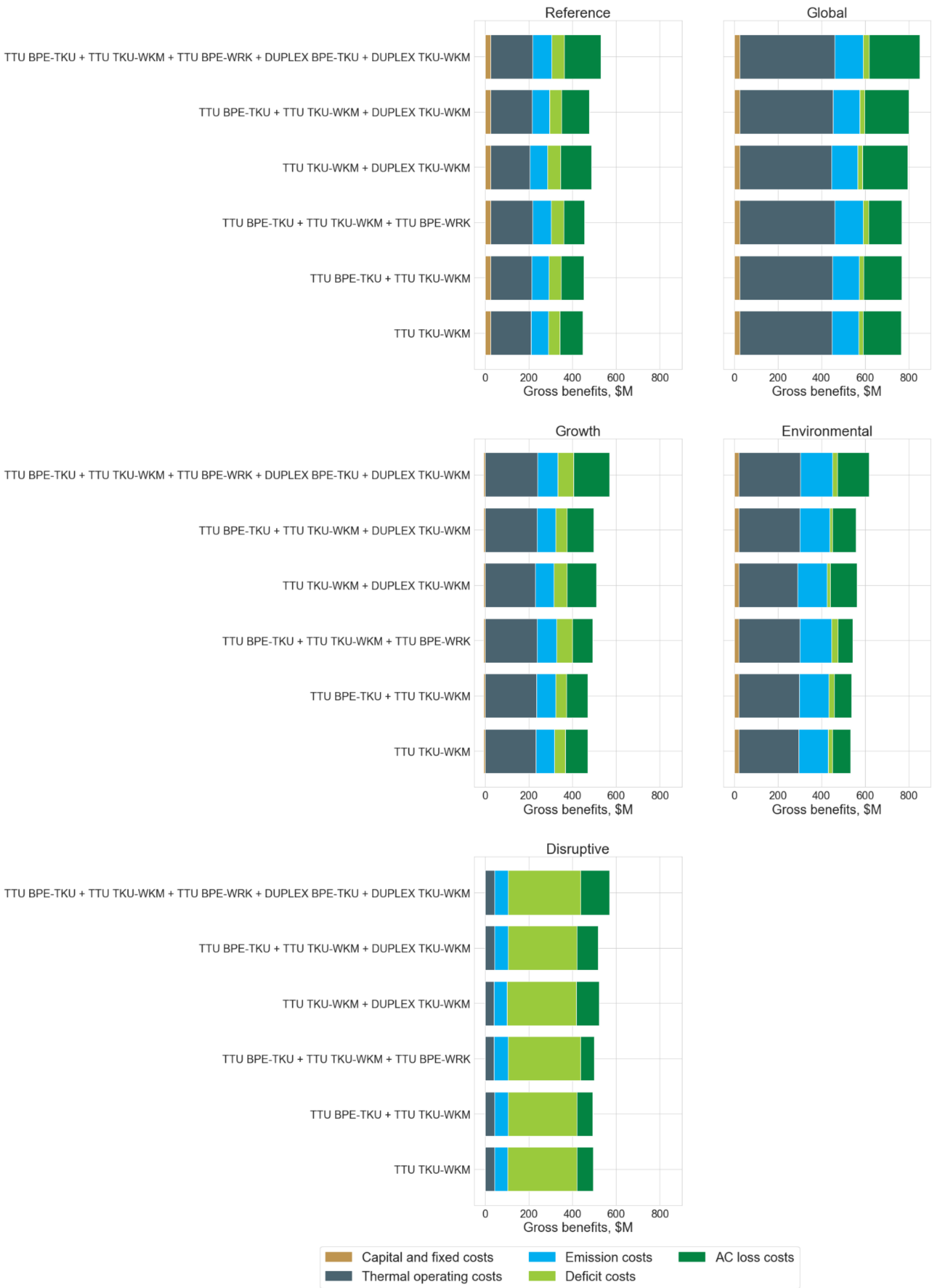


Figure 15: Gross benefits CNI AC transmission intermediate options

3.3.5 Gross Benefits: Investment Test Tiwai leaves 2024

We estimated investment test gross benefits for Tiwai leaves in 2024. We considered two HVDC options and nine AC transmission options.

The two HVDC options are:

- A statcom is installed in 2026 (referred to as the 'HVDC statcom' option in this attachment and Option B1 in Attachment C). HVDC north flow capacity is assumed to be 1200 MW.
- A statcom is installed in 2026 and a fourth cable is installed in 2027 (referred to as the 'HVDC fourth cable' option and Option B2 in Attachment C). HVDC north flow capacity is assumed to be 1400 MW, once the fourth cable is installed.

Error! Reference source not found. describes the nine AC transmission options considered for the i nvestment test. The preferred option for this application proposal - TTU BPE-WKM + DUPLEX TKU-WKM + TTU C LINE - is highlighted in light blue. These AC transmission options are intended to relieve constraints on the CNI transmission corridor and Wairakei Ring.

Table 9: Tiwai leaves 2024 AC transmission options

Option Number	Option Name	CNI AC Upgrades	Wairakei Ring Upgrades
	All options	All options include the facilitating projects discussed in Attachment C – Options Report.	
C6 + W1	TTU BPE-WKM + DUPLEX TKU-WKM + TTU C LINE	TTU the TKU-WKM circuits, installed Dec 2023. TTU the BPE-TKU circuits, installed Dec 2025. Duplex the TKU -WKM circuits, installed June 2027.	TTU the Wairakei C Line, installed June 2024.
C6 + W4	TTU BPE-WKM + DUPLEX TKU-WKM + TTU C LINE + TTU EDG-KAW + UPGRADE WKM-WRK	As above	TTU the EDG-KAW-3 circuit, installed Jun 2024. New line for ATI-WRK and duplex the ATI-WKM circuits, installed Jan 2028. TTU the Wairakei C Line, installed Jan 2029.
C6 + W7	TTU BPE-WKM + DUPLEX TKU-WKM + TTU EDG-KAW + NEW WRK-WKM	As above	TTU the EDG-KAW-3 circuit, installed Jun 2024. New line for WRK-WKM, installed Jan 2028.

Option Number	Option Name	CNI AC Upgrades	Wairakei Ring Upgrades
C8 + W1	TTU BPE-WKM + TTU BPE-WRK + DUPLEX BPE-WKM + TTU C LINE	TTU the TKU-WKM circuits, installed Dec 2023. TTU the BPE-TKU circuits, installed Dec 2025. Duplex the TKU-WKM circuits, installed Jun 2027. Duplex the TKU-WKM circuits, installed Feb 2030. TTU the BPE-WRK circuits, installed Nov 2031	TTU the Wairakei C Line, installed June 2024
C8 + W4	TTU BPE-WKM + TTU BPE-WRK + DUPLEX BPE-WKM + TTU C LINE + TTU EDG-KAW + UPGRADE WKM-WRK	As above	TTU the EDG-KAW-3 circuit, installed Jun 2024 New line for ATI-WRK and duplex the ATI-WKM circuits, installed Jan 2028 TTU the Wairakei C Line, installed Jan 2029
C8 + W7	TTU BPE-WKM + TTU BPE-WRK + DUPLEX BPE-WKM + TTU EDG-KAW + NEW WRK-WKM	As above	TTU the EDG-KAW-3 circuit, installed Jun 2024 New line for WRK-WKM, installed Jan 2028
C9 + W1	TTU BPE-WKM + NEW BPE-WRM + TTU C LINE	TTU the TKU-WKM circuits, installed Dec 2023. TTU the BPE-TKU circuits, installed Dec 2025. New line for BPE-WKM installed Dec 2029	TTU the Wairakei C Line, installed June 2024
C9 + W4	TTU BPE-WKM + NEW BPE-WRM + TTU C LINE + TTU EDG-KAW + UPGRADE WKM-WRK		TTU the EDG-KAW-3 circuit, installed Jun 2024 New line for WRK-WKM, installed Jan 2028
C9 + W7	TTU BPE-WKM + NEW BPE-WRM + TTU EDG-KAW + NEW WRK-WKM		TTU the EDG-KAW-3 circuit, installed Jun 2024 New line for ATI-WRK and duplex the ATI-WKM circuits, installed Jan 2028 TTU the Wairakei C Line, installed Jan 2029

Gross benefits are presented in Figure 16 for the HVDC Stacom option and nine AC transmission options. Figure 17 presents gross benefits for HVDC fourth cable option and nine AC transmission options. In terms of the relative share of gross benefits by cast category, similar observations can be made as discussed for the CNI AC transmission intermediate options. For a given scenario and HVDC option, significant differences in gross benefits can be observed across the range of AC grid transmission options. The change in gross benefits continues to be driven by AC loss benefits. The HVDC fourth cable increases gross benefits although the relative magnitude of the does vary by scenario.

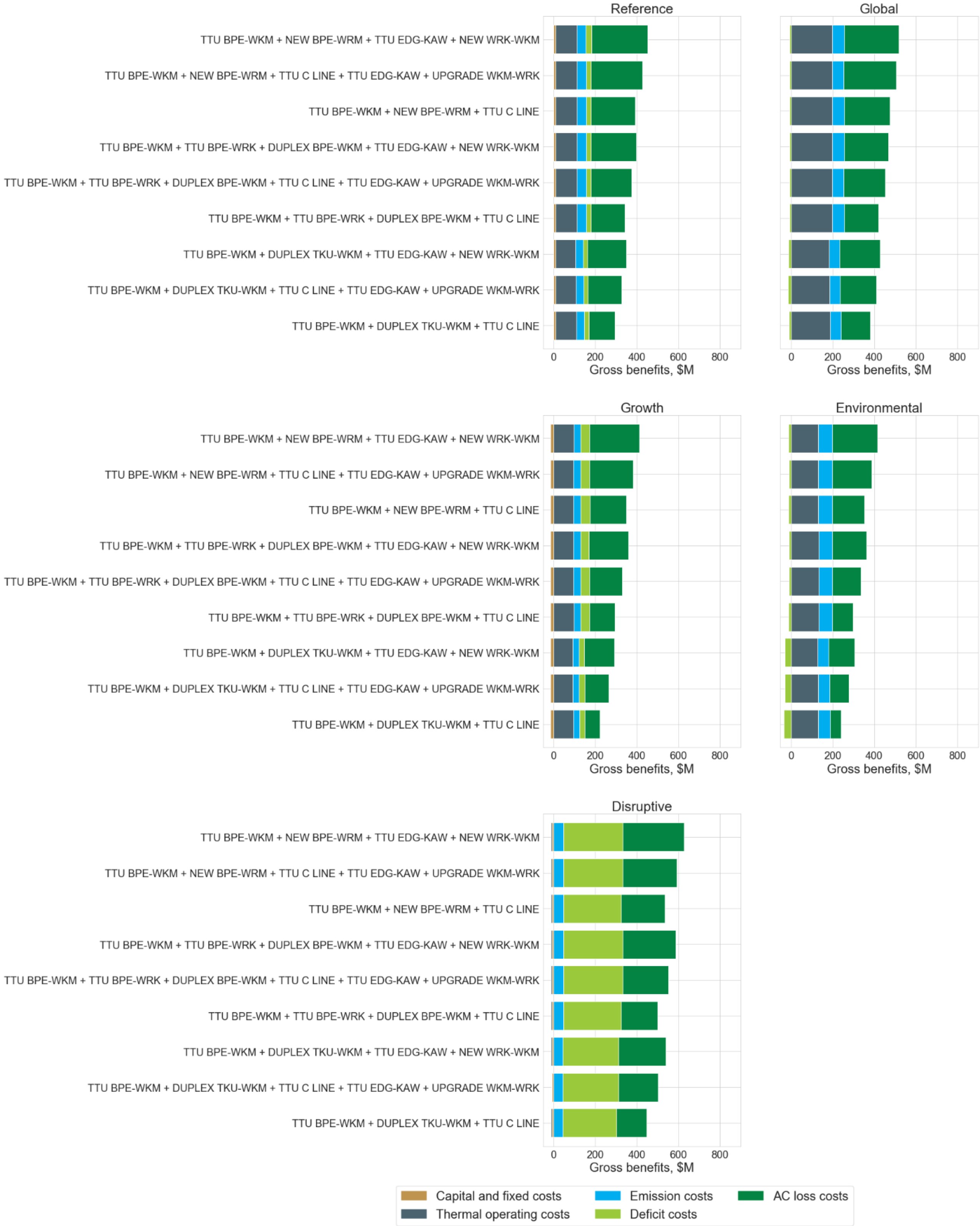


Figure 16: Gross benefits: Tiwai leaves 2024, AC transmission options with HVDC statcom in 2026

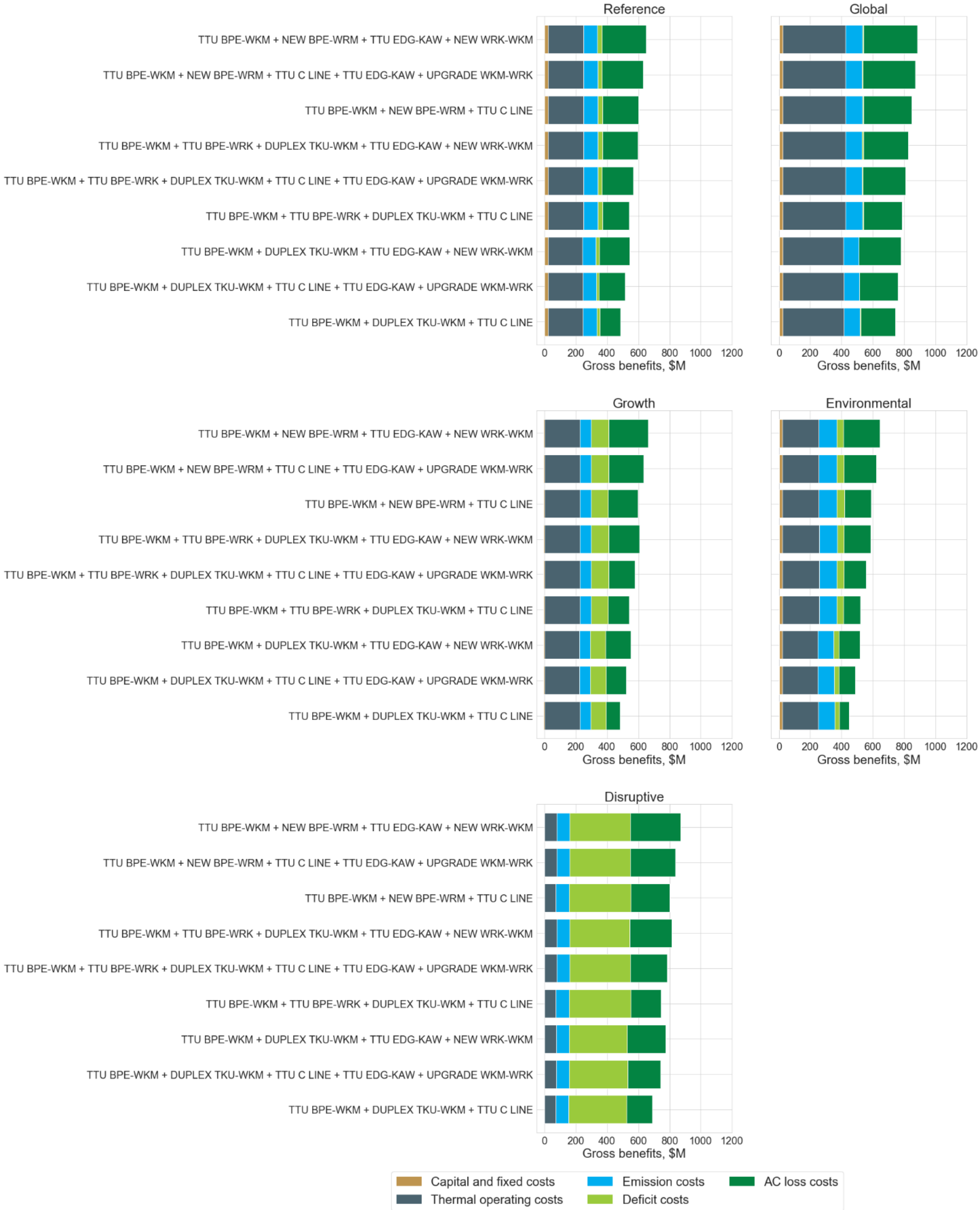


Figure 17: Gross benefits: Tiwai leaves 2024, AC transmission options with HVDC statcom in 2026, fourth cable 2027

3.3.6 Gross Benefits: Investment Test Tiwai leaves 2034

We have estimated investment test gross benefits for the application proposal preferred option if Tiwai leaves in 2034. We considered two HVDC options:

- A statcom is installed in 2026 and a fourth cable is installed in 20**27**.
- A statcom is installed in 2026 and a fourth cable is installed in 20**34**.

Both options have an assumed HVDC north flow capacity of 1200 MW in 2026 and 1400 MW once the HVDC fourth cable is installed.

Gross benefits for both options are shown in Figure 18. They are similar in magnitude to Tiwai Leaves in 2024. Other than for the Disruptive scenario they are relatively insensitive to the timing of the fourth cable.

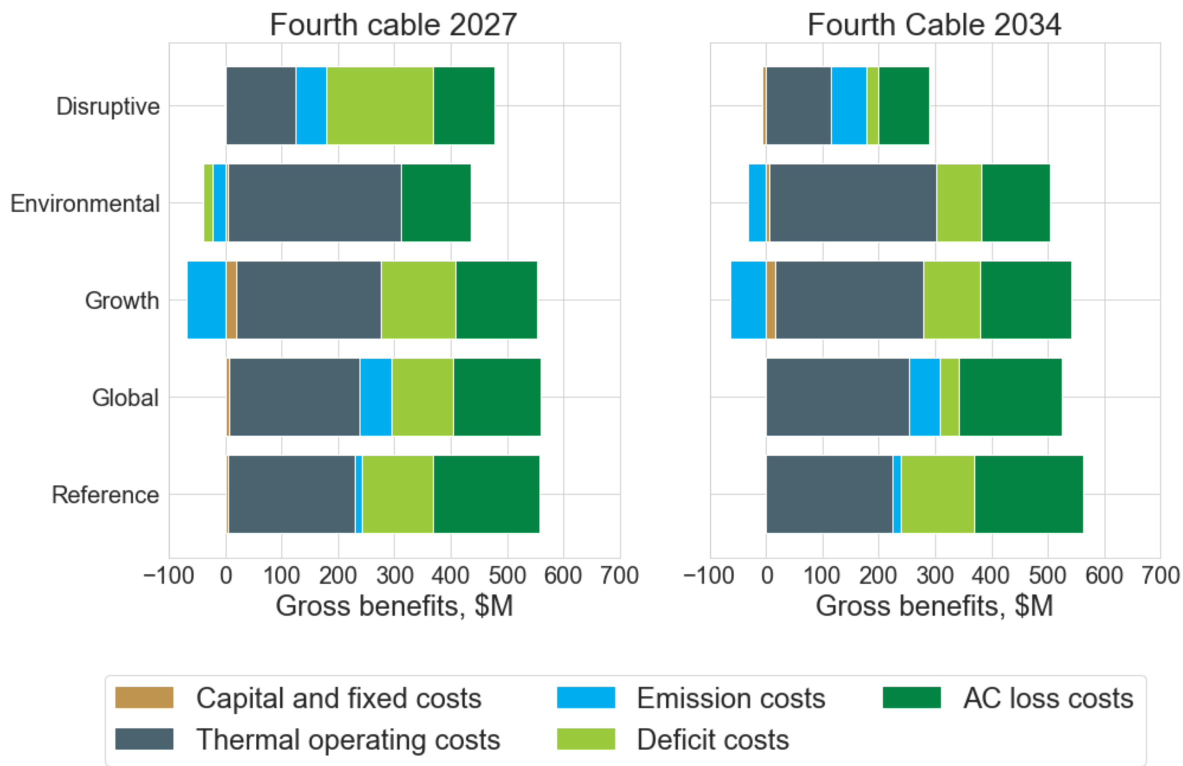


Figure 18: Gross benefits: Tiwai leaves 2034

3.3.7 Gross benefits over time: Tiwai leaves 2024, preferred option

Gross benefits for the preferred option over time are shown in Figure 19. These results are for Tiwai leaves in 2024 and for the HVDC option with the fourth cable installed in 2027. These show that the bulk of positive benefits occur post 2035.

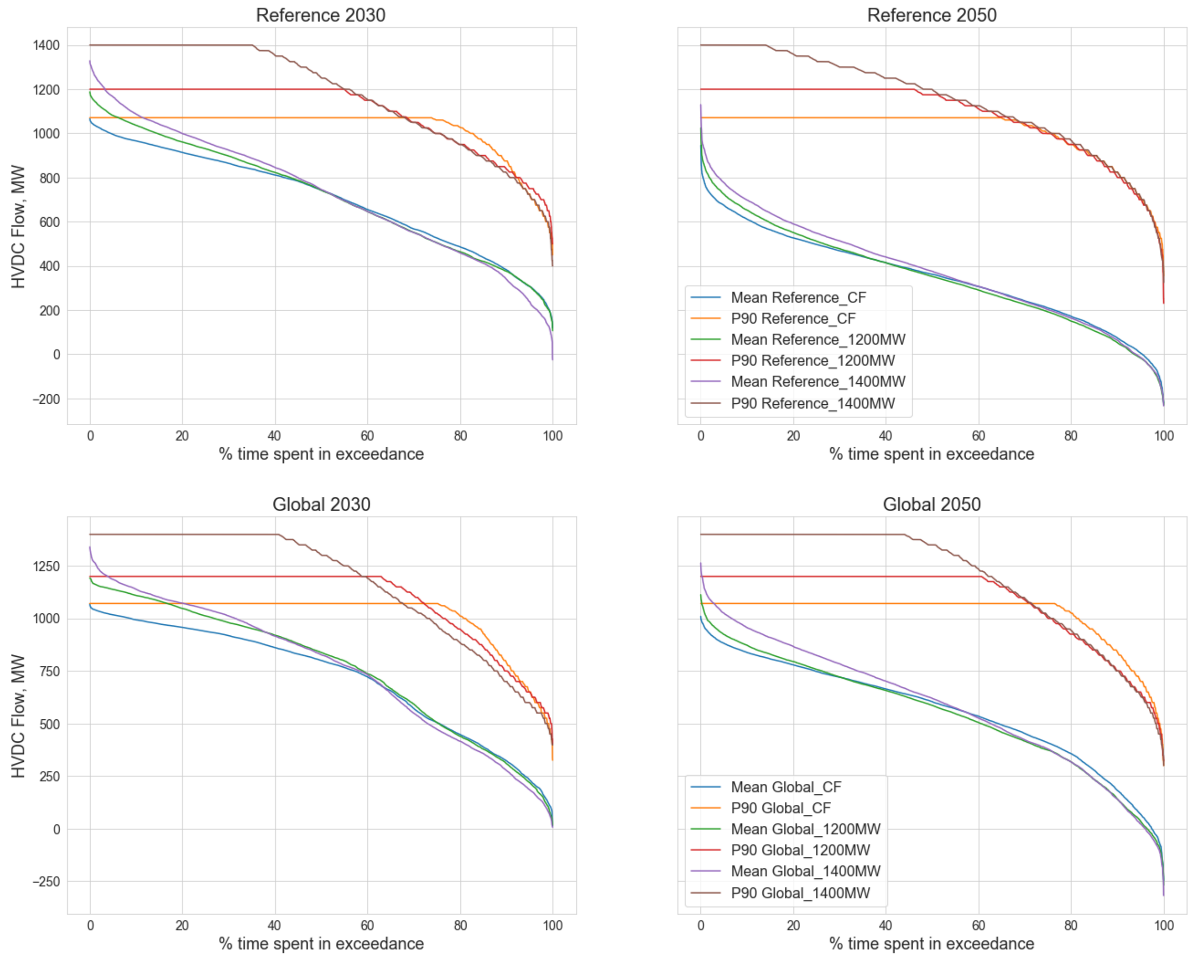
Figure 19: Preferred option gross benefits over time, Tiwai leaves 2024, HVDC fourth cable 2027

3.4 Preferred option HVDC flows

HVDC flows, in MW, for the preferred option, if Tiwai leaves in 2024, are shown in Figure 20. These charts are flow duration curves. They show the percentage of time that flows are at or above a certain value. For example, for the Reference 2030 chart (top left), looking at the brown curve labelled ‘P90 Reference_1400MW’, HVDC flows are equal to 1400MW for around 38% of time. Positive flows are in the Northwards direction.

For a given EDGS scenario, Figure 17 provides results for the counter factual (e.g. ‘Reference_CF’), the HVDC stacom option (e.g. ‘Reference_1200MW’) and HVDC fourth cable option (e.g. ‘Reference_1400MW’). Flows are provided as the mean over all hydro logical sequences (e.g. ‘Mean Reference_ …’) and as the 90th percentile of all hydrological sequences (e.g. ‘P90 Reference_ …’).

Increasing the capacity of the HVDC reduces the duration of time that the HVDC is constrained and increases mean transfer flows across the HVDC. Increased utilisation of the HVDC will reduce dependence on fossil fuels and in later years biofuels. This applies for all EDGS scenarios.



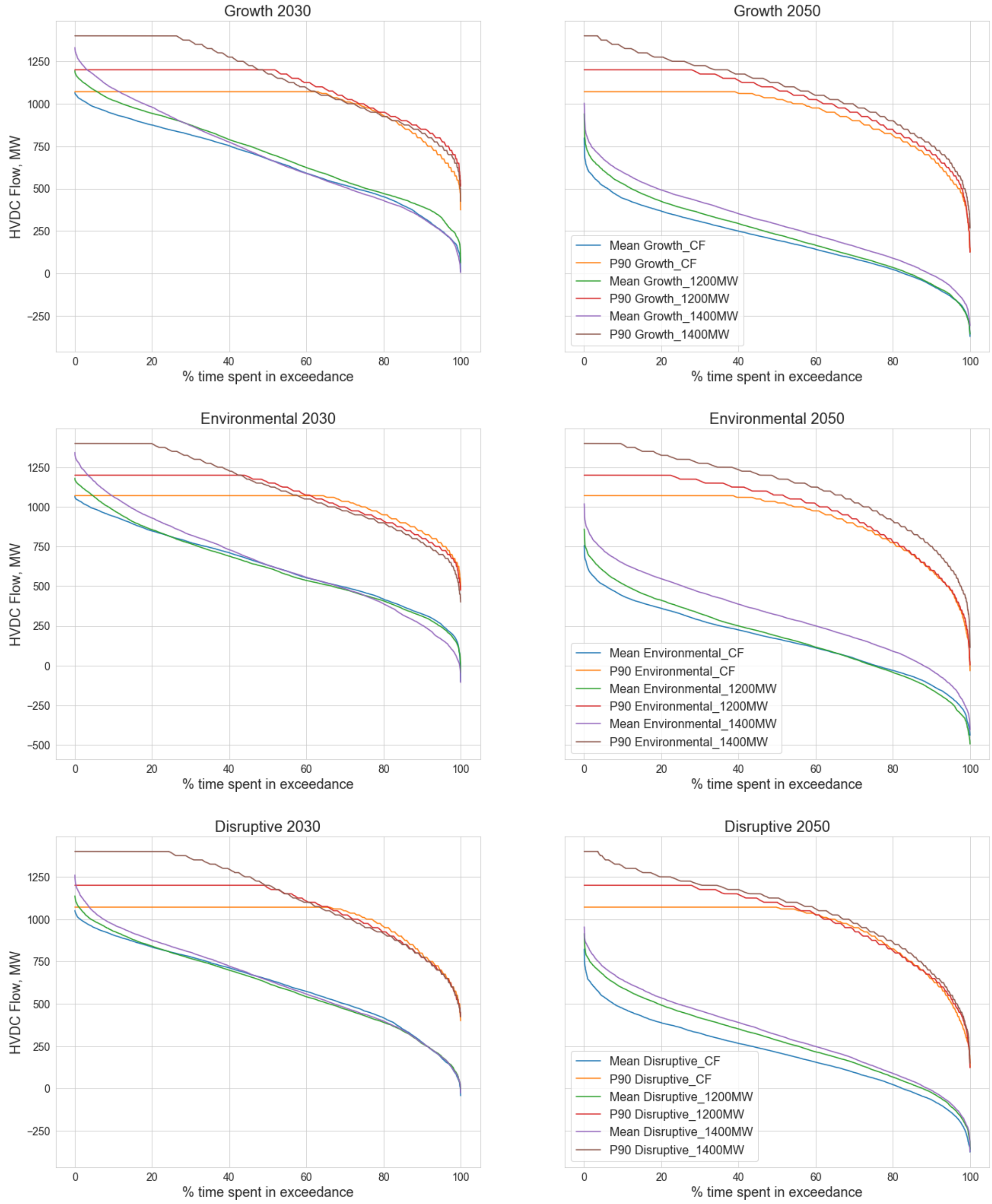


Figure 20: HVDC flows for the preferred option

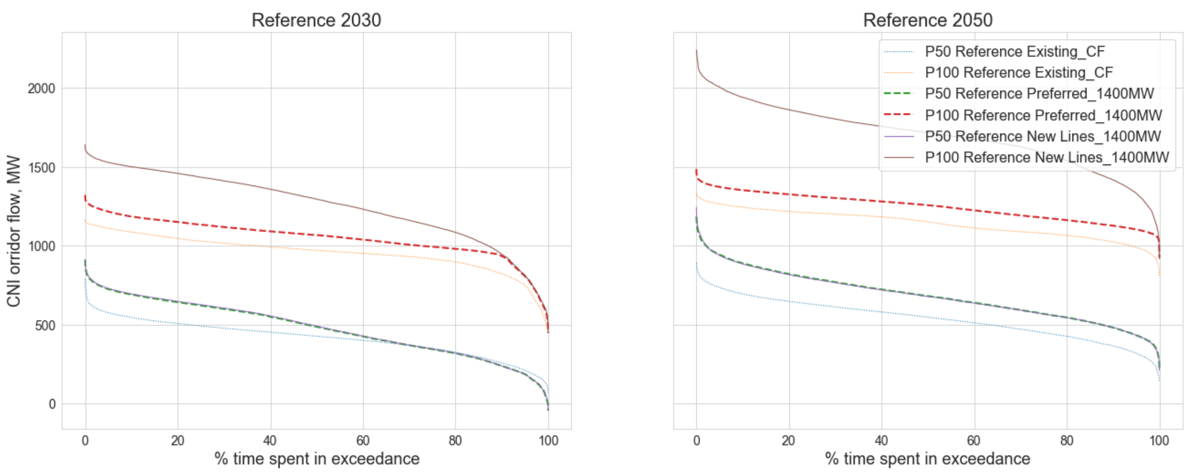
3.5 CNI corridor flows

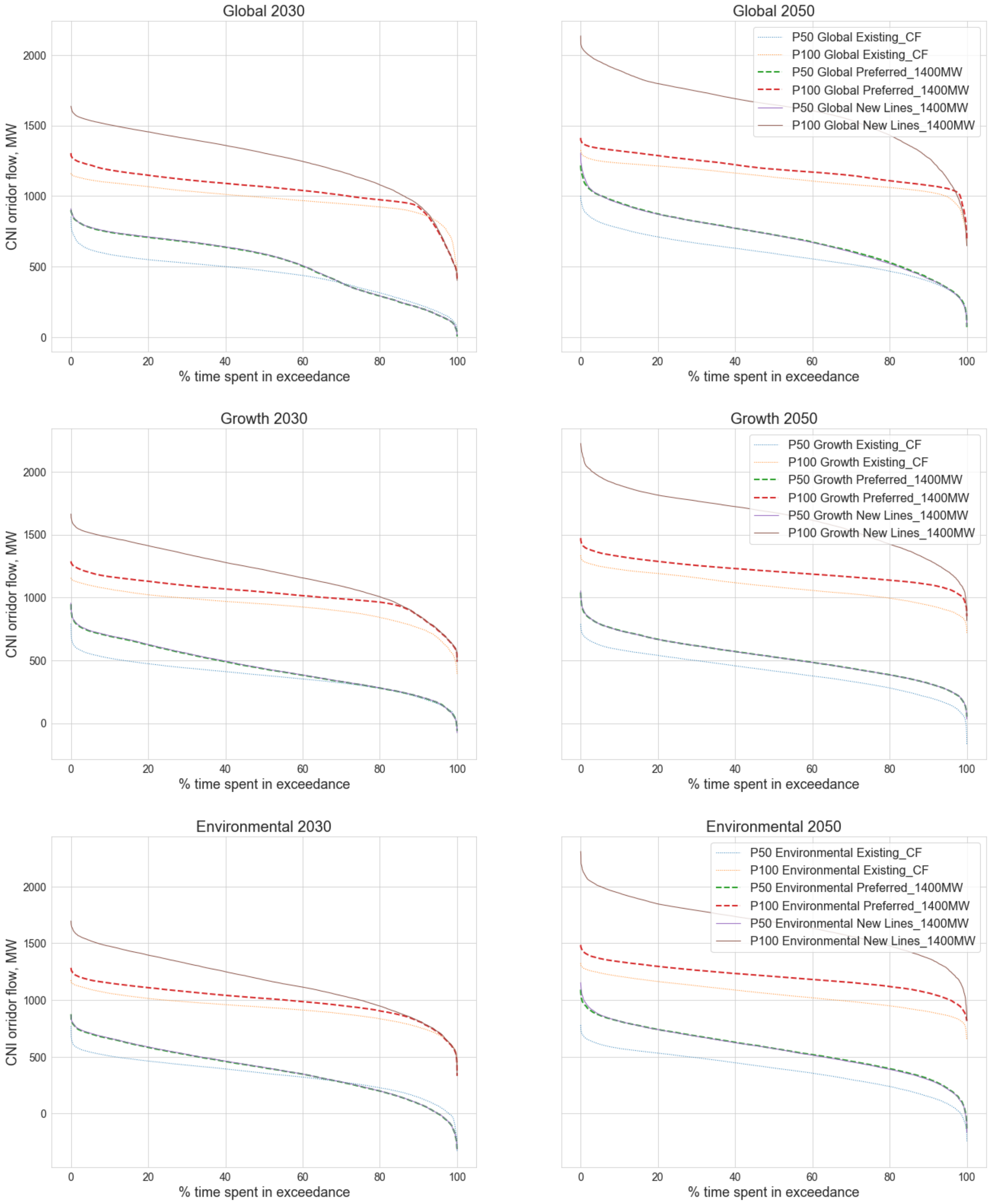
CNI corridor flows, in MW, if Tiwai leaves in 2024, and with a HVDC fourth cable installed in 2027 are shown in Figure 21. These charts show circuit flows summed across the main 220 kV circuits forming the CNI corridor (including BPE-TKU, BPE-TNG, BPE-BRK).

For a given EDGS scenario, Figure 21 provides results for the counter factual (e.g. ‘Reference Existing_CF’), the application proposal AC grid preferred option (e.g. ‘Reference Preferred_1400MW’) and for the AC grid option with a new line from BPE to WKM (e.g. ‘Reference New Line_1400MW’). Flows are provided for 50th and 100th percentiles over all hydrological sequences (e.g. ‘P50 Reference_ …’).

In general, increasing the capacity of the AC grid on the CNI corridor increases Northwards flows. P50 flows are the same for the preferred option and new line option. This indicates that average CNI corridor flows can be accommodated with preferred option. It also corresponds with the relatively moderate difference in benefits between the preferred option and the new line option.

The global scenario has a relatively large difference between factual and counterfactual flows. This corresponds to the relatively high thermal operating cost benefits for this option. Northwards flows are likely to be from either hydro or (later in the modelling horizon) wind generation.




Global 2030
Global 2050
Growth 2030
Growth 2050
Environmental 2030
Environmental 2050
CNI orridor flow, MW
% time spent in exceedance
P50 Global Existing_CF
P100 Global Existing_CF
P50 Global Preferred_1400MW
P100 Global Preferred_1400MW
P50 Global New Lines_1400MW
P100 Global New Lines_1400MW
P50 Growth Existing_CF
P100 Growth Existing_CF
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P50 Growth New Lines_1400MW
P100 Growth New Lines_1400MW
P50 Environmental Existing_CF
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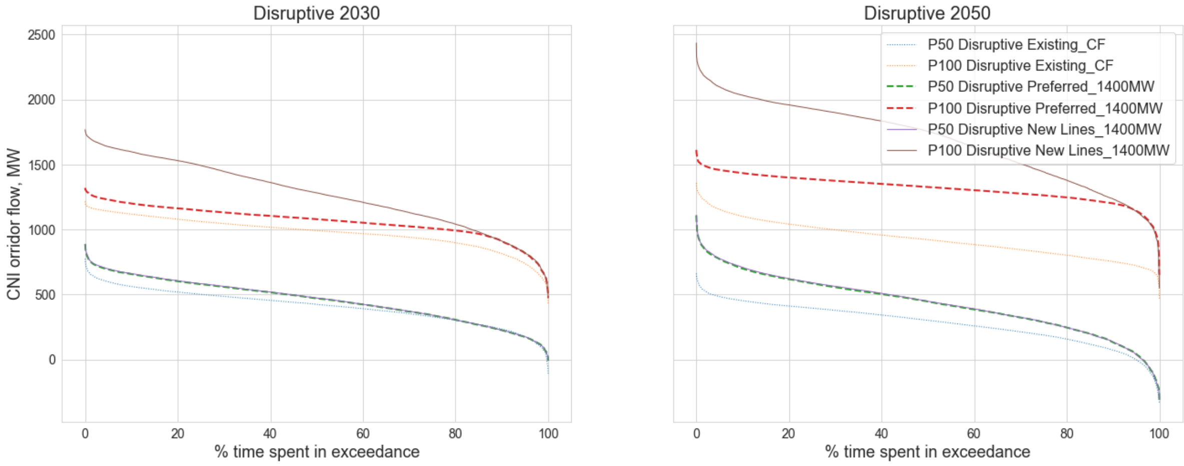

Figure 21: CNI corridor flows

3.6 Generation

Dispatched average generation by technology is shown in Figure 22. This is for the preferred option, if Tiwai leaves in 2024 and if the HVDC fourth cable is installed in 2027. Generation is averaged over all hydro sequences.

This shows that:

- Over time, wind and solar generation capture an increasing proportion of total generation. This is more so for those scenarios with high demand growth (Environmental, Growth and Disruptive). For these scenarios, wind and solar generation starts to rival that from hydro generation from around the beginning of the 2040s.
- The share of geothermal generation remains relatively static, although there is some modest growth for the Disruptive scenario.
- The proportion of generation from fossil fuels drops to relatively low levels, although this will vary somewhat with hydrological conditions.

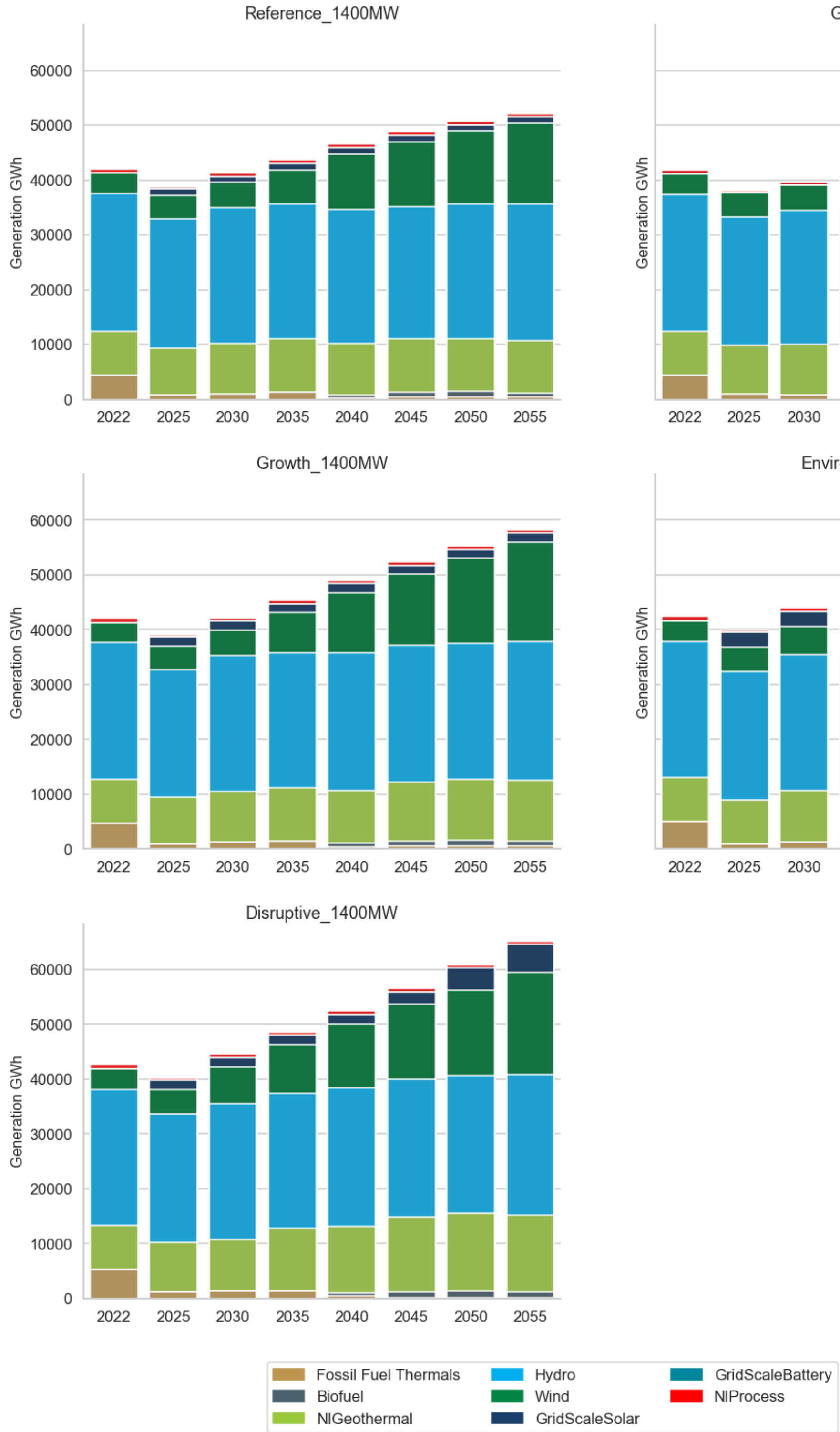

Figure 22: Yearly average dispatched generation by technology

3.7 Generation, preferred option factual vs counter factual

Yearly average generation dispatch differences between the application proposal preferred option factual and counterfactual are shown for fossil fuels and biofuels in Figure 23. The preferred option factual is with Tiwai leaving in 2024 and HVDC fourth cable installed in 2027. For this figure, a *negative* generation difference is where dispatched generation in the counterfactual is *greater* than dispatched generation in the factual. Where this is the case, thermal operating cost and emission cost (for fossil fuels) benefits will accrue to the factual.

Yearly average generation dispatch differences between the factual and counterfactual are shown for all technologies in Figure 24.

Factual and counterfactual dispatch differences are due to both differences in generation expansion plans and the impact of the preferred option transmission investment on dispatch (e.g. allowing greater Northwards flow).

Fossil fuel generation is displaced in the factual throughout out the modelling horizon. The greatest fossil fuel dispatch differences occur before around 2035, in line with the retirement of existing fossil fuel generation plant. After around 2035 biofuels generation begins to be displaced in the factual. While this generation is renewable and has no emissions costs it is nevertheless expensive, and benefits will flow to transmission options that are able to utilise this generation more efficiently.

Fossil fuels and biofuels generation is displaced, for the most part, by hydro generation until around 2035. From 2040 onwards, other renewable generation technologies start to play a role in displacing fossil fuels and biofuels. The type of renewable generation varies by scenarios:

- Wind displaces fossil fuels and biofuels across all scenarios.
- Solar generation only displaces fossil fuels and biofuels for the Disruptive scenario.
- Geothermal generation only displaces fossil fuels and biofuels for the Global scenario.

Figure 23: Yearly average fossil fuels and biofuels generation, counter factual vs preferred option factual (Tiwai leaves 2024 and HVDC fourth cable 2027)

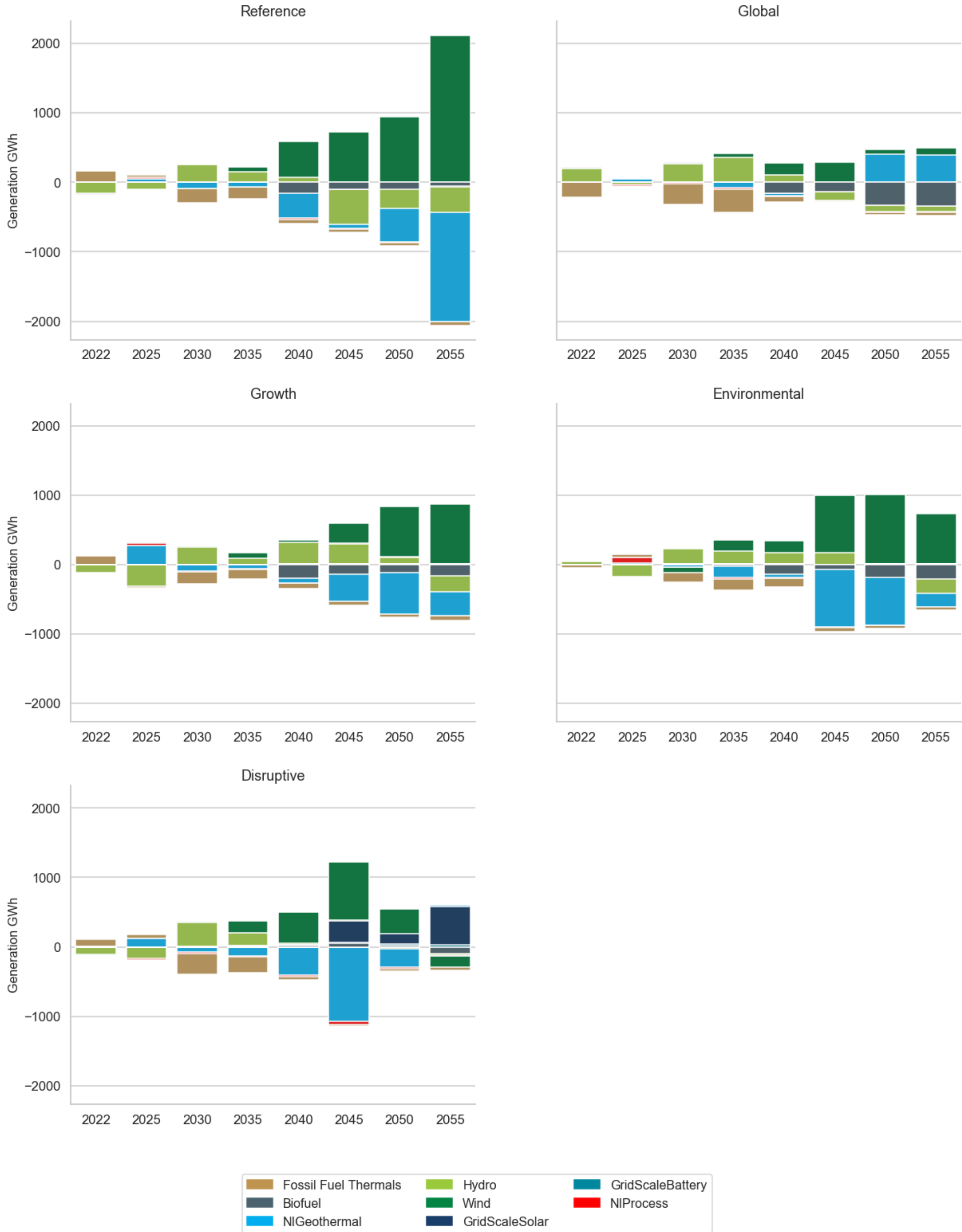

Figure 24: Yearly average generation, counter factual vs preferred option factual (Tiwai leaves 2024 and HVDC fourth cable 2027)

3.8 Demand response, preferred option factual vs counter factual

Our dispatch modelling also includes demand response[13]. This will typically be an option when supply is short whether due to dry years, renewable intermittency, or high demand. Yearly average demand response differences between the application proposal preferred option factual and counterfactual are shown in Figure 25. This is for Tiwai leaving in 2024 and HVDC fourth cable installed in 2027. For this figure, a *negative* difference is where demand response in the counterfactual is *greater* than demand response in the factual. Where this is the case, deficit costs benefits will accrue to the factual.

Disruptive scenario demand response differences are substantially higher than those in other scenarios. For this scenario greater reliance is placed on demand response rather than other peaking and year years solutions. Notably, less Biofuel generation is built in the Disruptive scenario (see section 3.2.1).

[13] Often referred to as deficit in a modelling context.

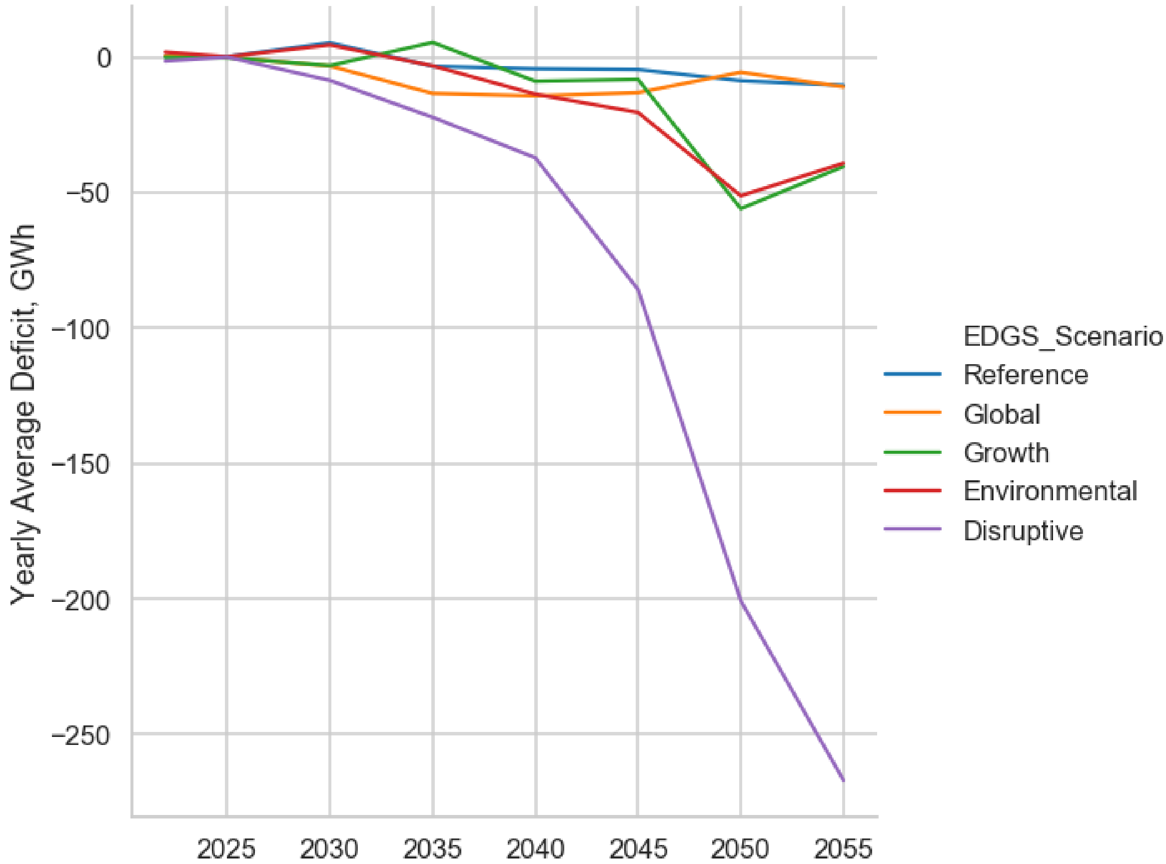

Figure 25: Yearly average deficit, counter factual vs preferred option factual (Tiwai leaves 2024 and HVDC fourth cable 2027)

For the same set of scenarios demand response as a percentage of hourly demand is shown in Figure 26. We show the P90, P95 and P97.5 percentile demand response. This is the proportion of time that demand response is at a given level or less, considering all hydro scenarios and hours each year.

The Disruptive scenario, once again, stands out. Demand response in this scenario reaches 6.5% of demand in 2050, for the P97.5 percentile. This means demand response could be 6.5% of demand or less for 97.5% of the time. Even then, the P90 chart indicates that for the bulk of the time there will be little or no demand response.

The assumed cost of demand varies according to its percentage of hourly demand. For example, demand response is valued at 800 $/MWh if its percentage of hourly demand is between 5 to 10%. We would expect that demand response at the levels shown and implied costs could be procured from a mixture of sources (e.g. hot water cylinders or industrial load shedding).

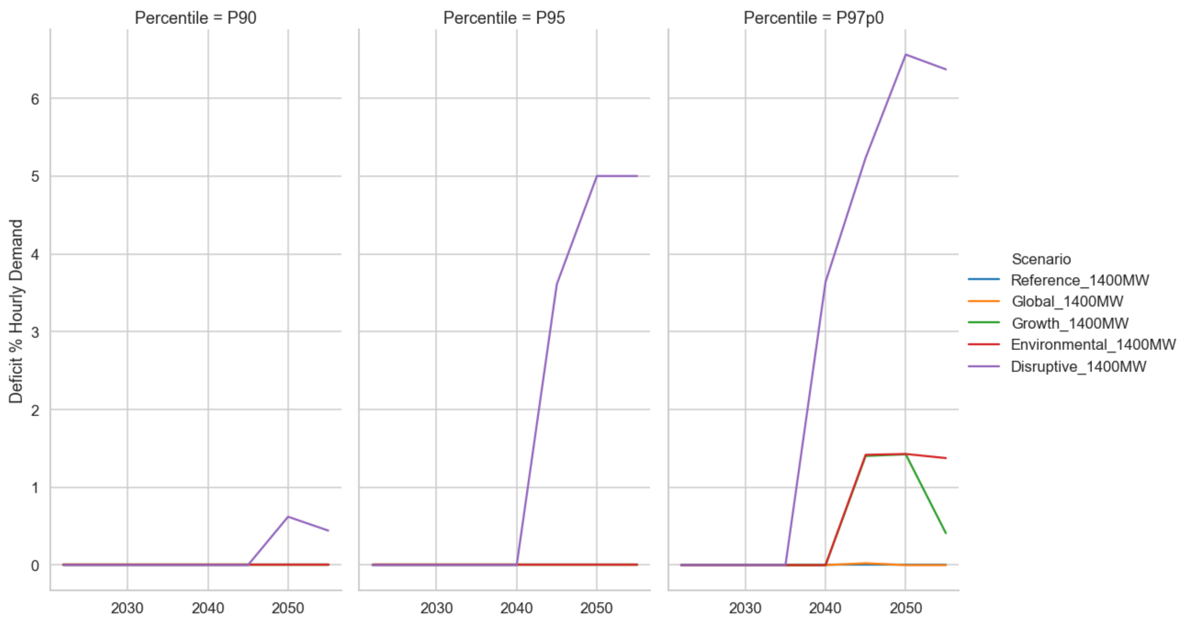

Figure 26: Deficit as a percentage of hourly demand: P90, P95, P97.5 over all combination of years and hydro scenarios in a year

3.9 AC Losses, preferred option factual vs counter factual

Yearly average AC loss differences between the application proposal preferred option factual and counterfactual are shown in Figure 27.Figure 27 This is for Tiwai leaving in 2024 and HVDC fourth cable installed in 2027. For this figure, a *negative* difference is where AC losses in the counterfactual are *greater* than AC losses in the factual. Where this is the case, AC loss costs benefits will accrue to the factual.

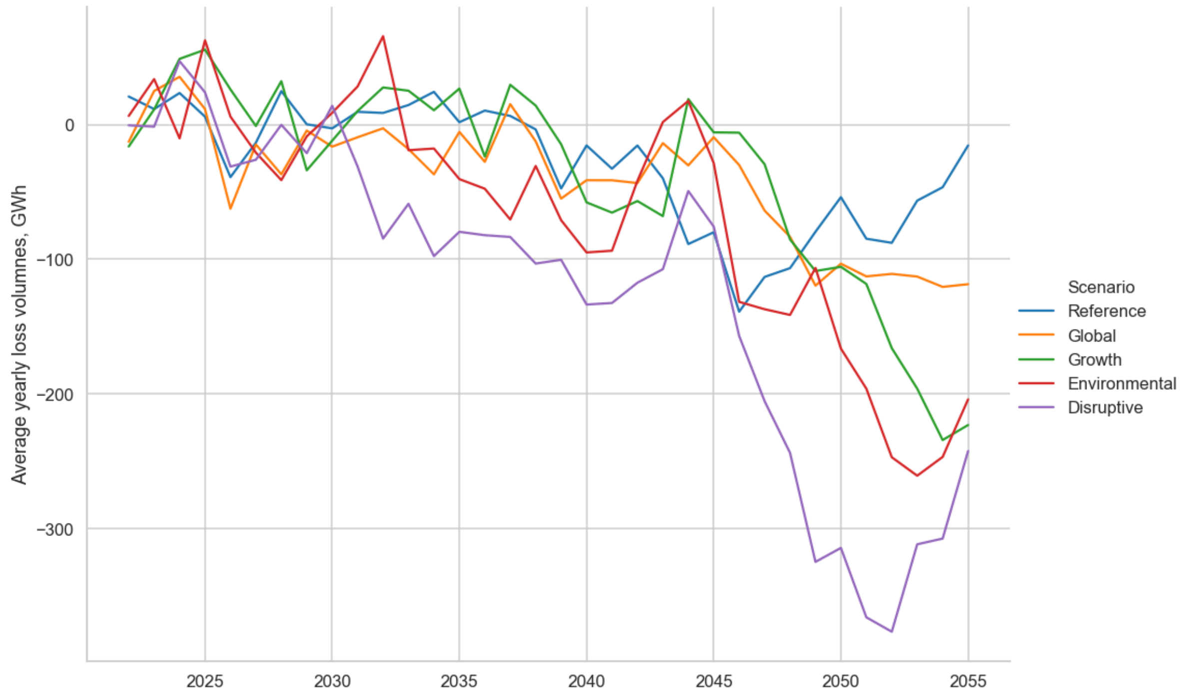

Figure 27: Average yearly AC losses, MWh, preferred option factual vs counterfactual (Tiwai leaves 2024, HVDC fourth cable 2027)

3.10 Island Self-Sufficiency

North Island generation self-sufficiency for the preferred option is shown in Figure 28. This is for Tiwai leaves in 2024 and the fourth cable is installed in 2027.

The left chart shows the difference, in GW, between North Island peak demand and North Island generation. We show the mean difference for the top 100 peak demand hours. This was done to reduce the impact of variable renewable generation. There is always a deficit of North Island generation. This means at times of peak demand generation must be imported into the North Island via the HVDC.

The right chart shows the difference, in GWh, between yearly North Island demand and yearly average North Island generation. North Island generation is average over all hydro sequences that we model. Again, there is always a deficit of North Island generation.

Both charts show that self-sufficiency reduces once Tiwai closes in 2024 and the North Island takes advantage of generation formally used to meet the industrial load at Tiwai. From 20230 self-sufficiency starts to improve as new generation is built in the North Island.

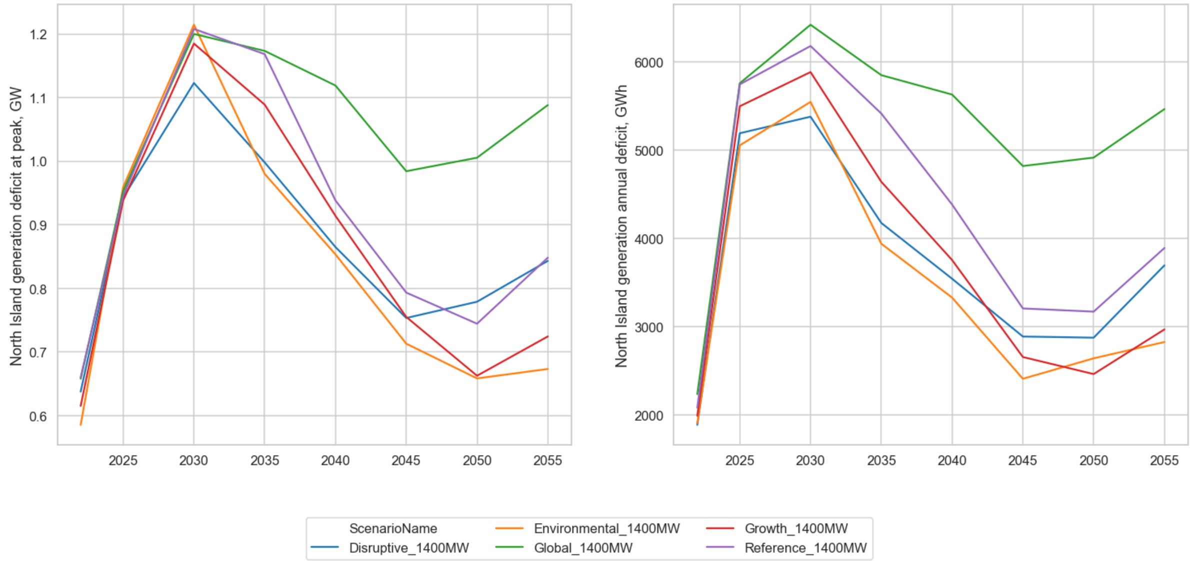

Figure 28: North Island Self Sufficiency, at peak demand (left) and averaged over a year (right)

3.11 Greenhouse gas emissions

Yearly average greenhouse gas emissions for the application proposal preferred option are shown in Figure 29. This is for Tiwai leaving in 2024 and HVDC fourth cable installed in 2027. The top left chart compares scenario yearly average emissions across all hydro sequences. The remaining charts show the variation of emissions with hydro inflows. For all scenarios emissions trends downwards, with a sharp drop prior to 2025. All emission profiles assume that 80% of geothermal greenhouse gas emissions are captured.

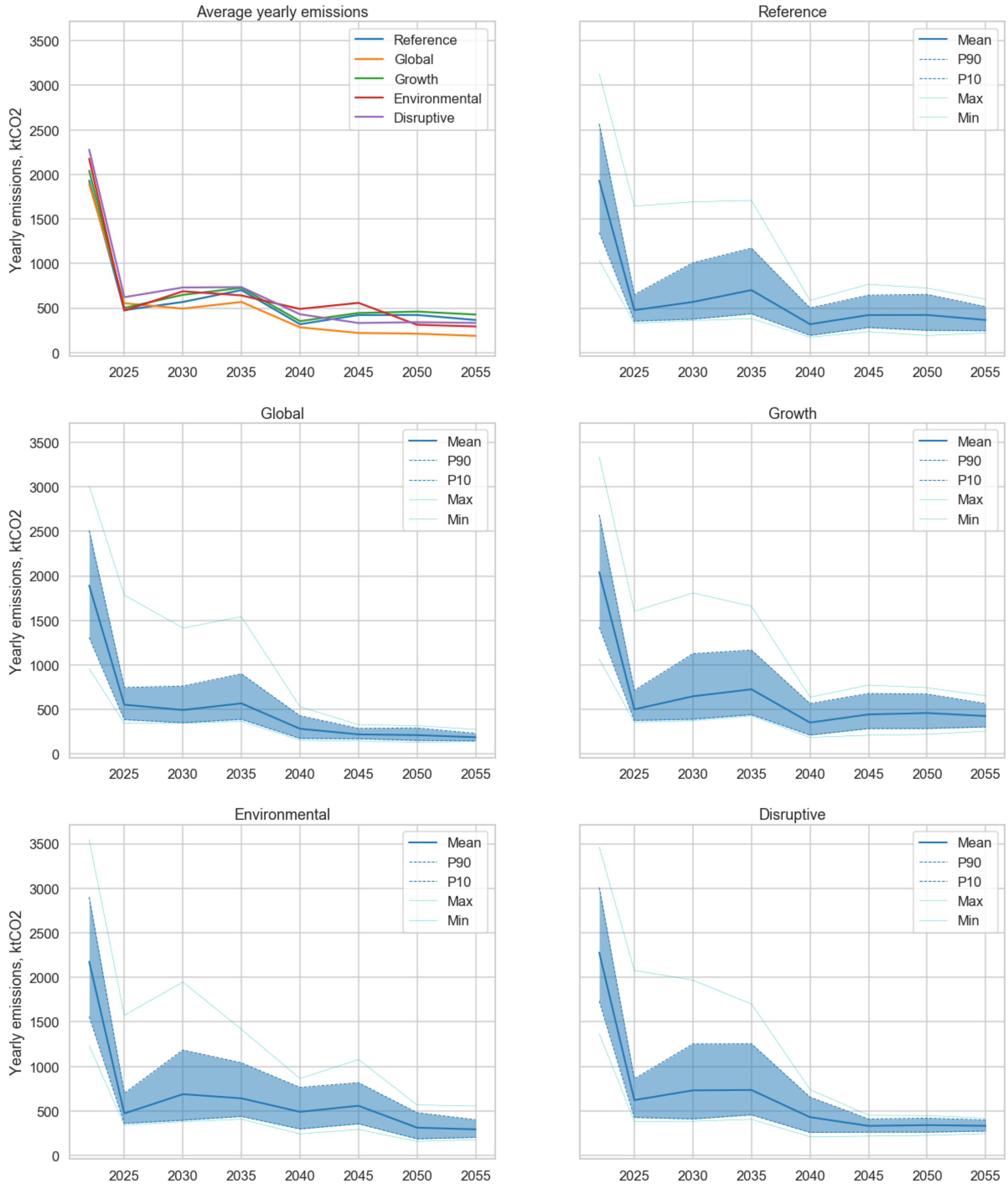

Figure 29: Yearly greenhouse gas emissions, preferred option with Tiwai leaves in 2024 and HVDC fourth cable in 2027

4.0 Appendix: TPM Assumption Differences

4.1 Introduction

This appendix details differences between the NZGP1 assumptions and those described in chapter 2 of the TPM's BBC Assumptions Book (v0.1).[14] In general, the BBC assumptions book contains the assumptions and detailed methodologies Transpower intends to apply for both the application of the investment test and for allocating and adjusting benefit-based charges under the TPM's standard methods.

In the course of the NZGP investigation, we have taken a different approach than set out in the assumptions book for a small number of assumptions.[15] The divergences are for practical reasons, in response to consultation feedback on this investigation, or due to the focus of this investigation.

Clause 43(5) of the TPM requires Transpower use the same assumptions used to apply the investment test when we calculate customer allocations for an investment, unless we do not consider these assumptions will result in allocations that are broadly in proportion to expected positive net-private benefits. We intend to apply the assumptions used in the investment test (as outlined in this document) when we apply the TPM to NZGP1 (unless otherwise required by the TPM).

We have not yet completed or consulted on the proposed starting BBI customer allocations for high-value benefit-based investments for NZGP1 – as signalled in our TPM consultation schedule we intend to do this ahead of the Commission's draft determination.

4.2 TPM Assumption Variations

Assumptions Book Paragraph	BBC assumptions book (v1.0)	NZGP1 Assumption Variation	Rationale
41	Cost declines for the Disruptive scenario: Advanced cost declines for geothermal, wind, solar, batteries	For the Disruptive scenario advanced cost declines are used for geothermal, solar and batteries. Conservative cost declines are used for wind.	To achieve a heavier bias toward solar generation technology in this scenario.

14 The first edition of the BBC Assumptions book was published on 15 September 2022

15 The assumptions book is non-binding (except as otherwise stated in the TPM)

Assumptions Book Paragraph	BBC assumptions book (v1.0)	NZGP1 Assumption Variation	Rationale
102	Within the simulation step, we use the actual historical inflow sequences. We run the simulation across all available hydro inflow sequences.	Hourly snapshot simulations have used 50 synthetic inflows sequences.	Synthetic inflow sequences rather than historic inflow sequences were used as a practical trade-off between precision and model solve time.
125	Gas, coal and diesel prices. See **Error! Reference source not found.**section 4.2.1.	See **Error! Reference source not found.**section 4.2.1.	Gas, coal and diesel prices have been used as consulted on during our review of the EDGS 2019 scenarios and in our NZGP1 short list consultation.
134	Carbon prices. See section 4.2.2.	Carbon prices. See section 4.2.2.	Carbon prices have been used as consulted on during our review of the EDGS 2019 scenarios and in our NZGP1 short list consultation.
138	We assume a deficit cost of $600/MWh in OptGen and SDDP.	First 5% of demand: $600/MWh Between 5% and 10% of demand: $800/MWh Between 10% and 15% of demand: $2,000/MWh Greater than 15% of demand: $10,000/MWh	We have modelled escalating deficit costs (i.e. demand response) to reflect the possibility of higher costs during peak periods, as opposed to the approach in the assumptions book which adjusts deficit costs in post-processing if necessary (and if using clause 52 of the TPM).

Assumptions Book Paragraph	BBC assumptions book (v1.0)	NZGP1 Assumption Variation	Rationale
155	The earliest commissioning date for consented wind projects is equal to the current year plus four years.	The earliest commissioning date for Wairarapa wind generation projects is 2035. All other wind generation projects are consistent with the BBC Assumptions Book.	Wairarapa wind generation projects do not appear to be of immediate interest to generation investors.
155	The biofuel peaker has an earliest commissioning date of 2035.	For the Environmental Scenario the biofuel peaker has an earliest commissioning date of 2030. Other scenarios are consistent with the BBC Assumptions Book.	The biofuel peaker can be built earlier in the Environmental Scenario so that it is consistent with the higher carbon price assumed for NZGP1 for this scenario.
155	New thermal generation projects have an earliest commissioning date of the current year plus four.	The Stratford CCGT project has an earliest commissioning date of 2025.	This is to allow the option of replacing the Taranaki Combined Cycle (TCC) project which retires in 2025.
159	New open cycle gas turbines have a composite outage rate of 3% and capital cost of 1,030 $/kW	The Otorohanga Peaker Units 1 – 3 have a composite outage rate of 13% and capital cost of 1,252 $/kW	The capital cost is based on Waikato Power Plant estimated costs provided in the 2020 MBIE thermal generation stack update[16], page 65 using a NZD:USD exchange rate of 0.72 for the foreign capital cost component. The composite outage rate is from the same document, Table 5-1.

[16] MBIE 2020 Thermal Generation Stack Update

Assumptions Book Paragraph	BBC assumptions book (v1.0)	NZGP1 Assumption Variation	Rationale
162	The Tauhara2a geothermal plant has a maximum build capacity of 152 MW.	The Tauhara2a geothermal plant has a maximum build capacity of 168 MW.	The maximum build capacity was updated to align with the 21 June 2022 Contact International Roadshow Presentation (page 32)[17].
162	The Tauhara2a geothermal plant has a maximum build capacity of 125 MW.	The Tauhara2a geothermal plant has a maximum build capacity of 73.6 MW.	The maximum build capacity of Tauhara2a was adjusted downwards to account for Contact's new geothermal project at Te Huka. The Te Huka project is modelled in NZGP1 as a committed project with an installed capacity of 51.4 MW[18]. As the Te Huka utilises the same geothermal resource as Tauhara2b, the later project's installed capacity was adjusted downwards to ensure that we were not over stating or double counting its future development potential.
162	Capital costs of geothermal generation	Capital costs of geothermal generation are 50% of those in the BBC Assumptions Book	Geothermal generation costs were reduced to reflect feedback about the potential for geothermal generation received during the consultation on EDGS variations. The reasoning is described

[17] Contact International Roadshow Presentation, 21 June 2022
[18] Contact website

Assumptions Book Paragraph	BBC assumptions book (v1.0)	NZGP1 Assumption Variation	Rationale
			in the NZGP1 Scenarios Update, page 18[19].
165	The Kaiwaikawe wind project has a maximum build capacity of 60 MW.	The Kaiwaikawe wind project has a maximum build capacity of 75 MW.	The maximum build capacity was updated to be consistent with information from Mercury Energy. See 30 June 2022 year end financial results presentation, page 15[20].
168 - 169	Solar plant available to be built and near term planned solar farms.	This information has been updated using information from Transpower connection inquiries – see section 2.4.2.	The information from Transpower connection inquiries is more up to date than the solar generation project information provided in the solar generation stack and the BBC assumptions book.

[19] Transpower, NZGP Scenarios Update

[20] Mercury Energy, 30 June 2022 year end financial results presentation

4.2.1 Fuel Price Assumption Variations

Year	Gas Price - v1.0 of assumptions book	Gas Price - NZGP1	Coal Price - v1.0 of assumptions book	Coal Price - NZGP1	Diesel Price - v1.0 of assumptions book	Diesel Price - NZGP1
2022	9.44	**6.65**	13.54	**7.79**	36.27	**28.78**
2023	9.19	**6.65**	12.97	**7.79**	36.70	**30.01**
2024	8.93	**6.65**	12.39	**7.79**	37.13	**31.24**
2025	8.68	**6.65**	11.82	**7.79**	37.56	**32.48**
2026	8.42	**6.65**	11.24	**7.79**	37.99	**33.71**
2027	8.17	**6.65**	10.67	**7.79**	38.42	**34.94**
2028	7.91	**6.65**	10.09	**7.79**	38.85	**36.18**
2029	7.66	**6.65**	9.52	**7.79**	39.28	**37.41**
2030	7.40	**6.65**	8.94	**7.79**	39.71	**38.64**
2031	7.15	**6.8875**	8.37	**7.79**	40.14	**39.61**
2032	6.89	**6.8875**	7.79	**7.79**	40.57	**40.57**
2033	6.89	**6.8875**	7.79	**7.79**	41.54	**41.54**
2034	6.89	**6.8875**	7.79	**7.79**	42.51	**42.51**
2035	6.89	**6.8875**	7.79	**7.79**	43.47	**43.47**
2036	6.89	**6.8875**	7.79	**7.79**	44.44	**44.44**
2037	6.89	**6.8875**	7.79	**7.79**	45.40	**45.4**
2038	6.89	**6.8875**	7.79	**7.79**	46.37	**46.37**
2039	6.89	**6.8875**	7.79	**7.79**	47.34	**47.34**
2040	6.89	**6.8875**	7.79	**7.79**	48.30	**48.3**
2041	7.84	**7.8375**	7.79	**7.79**	48.30	**48.3**

Year	Gas Price - v1.0 of assumptions book	Gas Price - NZGP1	Coal Price - v1.0 of assumptions book	Coal Price - NZGP1	Diesel Price - v1.0 of assumptions book	Diesel Price - NZGP1
2042	7.84	**7.8375**	7.79	**7.79**	48.30	**48.3**
2043	7.84	**7.8375**	7.79	**7.79**	48.30	**48.3**
2044	7.84	**7.8375**	7.79	**7.79**	48.30	**48.3**
2045	7.84	**7.8375**	7.79	**7.79**	48.30	**48.3**
2046	7.84	**7.8375**	7.79	**7.79**	48.30	**48.3**
2047	7.84	**7.8375**	7.79	**7.79**	48.30	**48.3**
2048	7.84	**7.8375**	7.79	**7.79**	48.30	**48.3**
2049	7.84	**7.8375**	7.79	**7.79**	48.30	**48.3**
2050	7.84	**7.8375**	7.79	**7.79**	48.30	**48.3**

4.2.2 Carbon Price Assumption Variations

Year	Carbon Price – v1.0 of assumptions book	Carbon Price - NZGP1: Reference, Global, Growth and Disruptive Scenarios	Carbon Price - NZGP1: Environmental Scenario
2022	72.90	**51.68**	**40.84**
2023	80.30	**62.53**	**51.68**
2024	87.69	**73.37**	**69.00**
2025	95.09	**84.21**	**85.00**
2026	102.48	**95.05**	**102.00**
2027	109.88	**105.89**	**119.00**
2028	117.27	**116.74**	**136.00**
2029	124.67	**127.58**	**152.00**

Year	Carbon Price – v1.0 of assumptions book	Carbon Price - NZGP1: Reference, Global, Growth and Disruptive Scenarios	Carbon Price - NZGP1: Environmental Scenario
2030	132.06	138.42	169.00
2031	139.46	142.57	186.00
2032	146.85	146.85	196.00
2033	151.25	151.25	207.00
2034	155.79	155.79	218.00
2035	160.47	160.47	229.00
2036	165.28	165.28	239.00
2037	170.24	170.24	250.00
2038	175.35	175.35	261.00
2039	180.61	180.61	271.00
2040	186.02	186.02	282.00
2041	191.60	191.6	293.00
2042	197.35	197.35	299.00
2043	203.27	203.27	306.00
2044	209.37	209.37	312.00
2045	215.65	215.65	319.00
2046	222.12	222.12	325.00
2047	228.79	228.79	331.00
2048	235.65	235.65	338.00
2049	242.72	242.72	344.00
2050	250.00	250.00	351.00

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