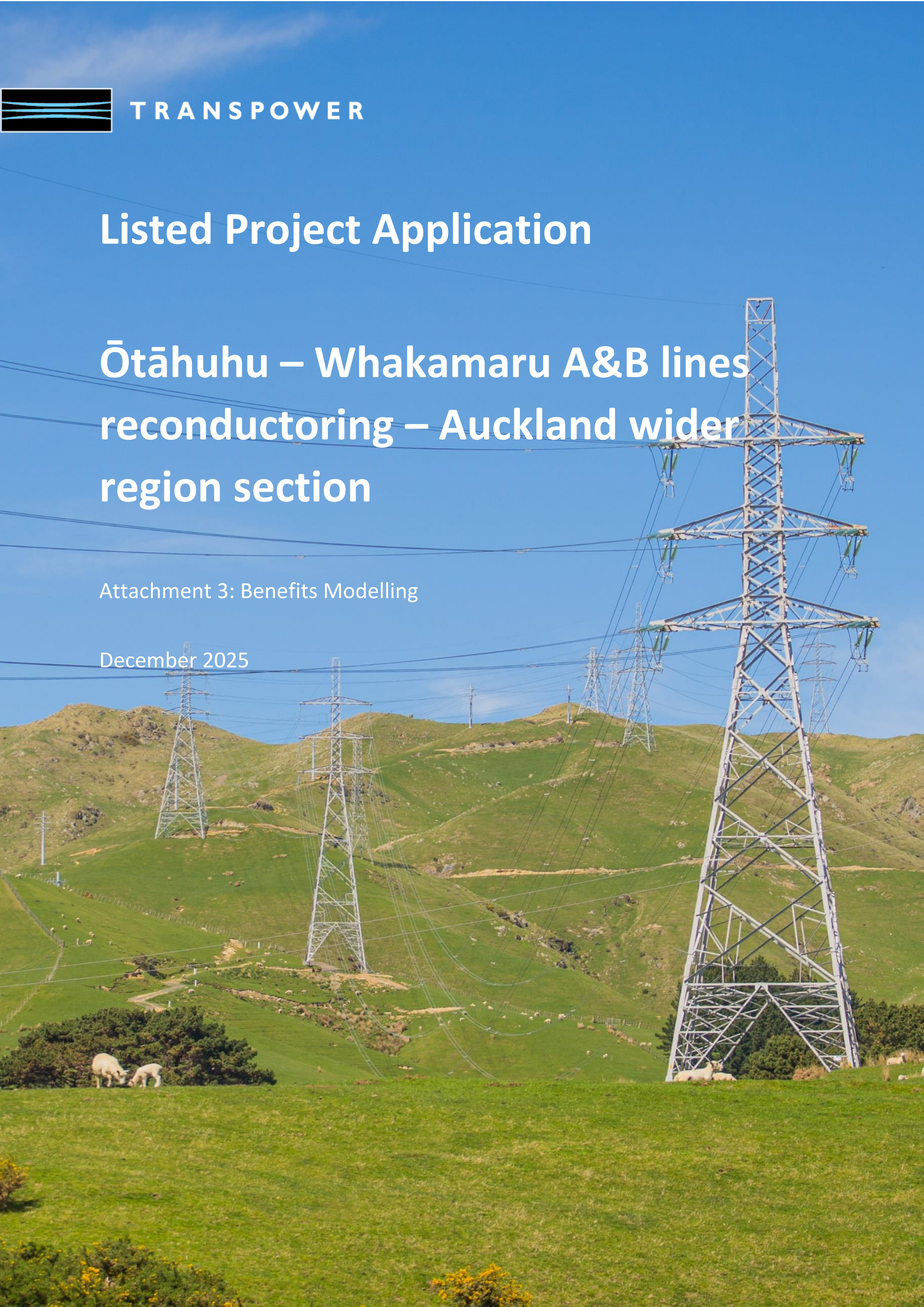
TRANSPOWER

Listed Project Application

Ōtāhuhu – Whakamaru A&B lines reconductoring – Auckland wider region section

Attachment 3: Benefits Modelling

December 2025



Purpose

This Attachment forms part of the OTA–WKM A&B Reconductoring Listed Project Application.

The purpose of this Attachment is to describe how we have calculated the benefits of the investment options for the OTA–WKM A&B Reconductoring listed project. We used models of the New Zealand electricity system to calculate the benefits of alternative investment options to meet the investment needs for the OTA–WKM A&B lines, and to inform our decision-making for this listed project. Our benefits calculation for this analysis is consistent with how we calculate benefits when we are determining expected net electricity market benefit for a major capex investment option.

Contents

1 Benefits Modelling Approach

This Section describes the approach used in our analysis to model and calculate the benefits of the investment option.

In this Attachment we refer to the investment options as a single **factual reconductoring option**. This is because we consider the quantified benefits of the investment options to be the same, as the additional capacity in the higher temperature conductors can only be accessed if the remaining sections of the OTA–WKM A&B lines are up-rated in future. The investment options are differentiated from each other by their project costs rather than their benefits.

The **counterfactual** is partial decommissioning the OTA–WKM A&B lines.

1.1 Overview

We use models of the New Zealand electricity system to calculate the benefits of alternative investment options to provide transmission into the Waikato, Auckland and Northland (**WUNI**) region.

The key components of our analysis are:

- **Power system analysis**. Conducted by our system planning team using DigSILENT's Power Factory software. This provides inputs into our generation dispatch simulation modelling.
- **Generation expansion planning**. We find the lowest cost combination of new generation projects required to meet forecast demand. For this analysis we use PSR Inc's OptGen software. Like the demand scenarios, the generation expansion plans are developed for the Growth, Reference and Environmental scenarios of MBIE's2019 Electricity Demand and Generation Scenarios (**EDGS**), with variations[1]. We selected three of the five 2019 EDGS scenarios (which we refer to as the **selected 2019 EDGS scenarios**) as this simplified the modelling while covering a wide range of demand and generation inputs. We did not use the Global scenario due to its unreasonably low level of growth. The Disruptive scenario is within the range of the three selected 2019 EDGS scenarios and therefore does not provide additional insights. The original OptGen expansion plans for each selected 2019 EDGS scenario are modified to improve revenue adequacy and limit Auckland and Northland (the upper North Island (**UNI**) region) generation.
- **Generation dispatch simulations**. These simulations estimate electricity system operating costs for the counterfactual and factual reconductoring option. For this, we use PSR Inc's SDDP software with generation dispatch simulations developed for the selected 2019 EDGS scenarios.

Our modelling provides estimates of electricity system costs for the counterfactual and factual reconductoring option. The benefits of the factual reconductoring option are then calculated as the difference between the system costs of the factual reconductoring option and the system costs of the counterfactual.

[1] See Attachment 2 for further information about the scenarios we have used.

For this analysis, we have used a WUNI2[2] modelled project comprised of duplexing the southern section[3] of the OTA–WKM A&B lines and a connection to Ōhinewai (**main case**). For our sensitivity analysis, we have used an alternative WUNI2 modelled project involving series compensation on the Brownhill-Whakamaru circuits excluding the tee to Ōhinewai and without duplexing the southern section (**sensitivity case**).

The main case is used in the "b" variations of the counterfactual (**Option 0b**) and factual reconductoring option (**Option 1b**). The sensitivity case is used in the "a" variations of the counterfactual (**Option 0a**) and factual reconductoring option (**Option 1a**). Hourly dispatch simulations are carried out for these four option and case combinations in this analysis.

The main case and sensitivity case are further described and illustrated in Appendix A2.

The main case counterfactual and main case factual reconductoring option (the "b" variations) are the principal basis for our analysis and selection of our preferred option.

1.2 Power System Analysis

Power system analysis, using DigSILENT's Power Factory software, provides key inputs to the transmission network models used for our generation dispatch simulations.

Transmission network constraints are derived from power system analysis and defined for both the counterfactual and factual reconductoring option. These constraints ensure flows within the OTA–WKM A&B area mimic actual market conditions. Constraints are applied to limit circuit flows so as to ensure circuit thermal ratings are respected in the event of a contingency (failure of a line, generator or transformer) or to avoid voltage stability issues. These constraints may limit flows substantially below the thermal rating of a circuit.

More technically, only network constraints that cannot be modelled in our generation dispatch simulation software need to be produced through power systems analysis. Our generation dispatch simulations use a simplified, linear, DC load flow model. Thermal N and N-1 limits can be captured within the simulation model dynamically, resulting in security constrained dispatch outcomes. However, some constraints, such as voltage stability constraints, cannot be modelled explicitly in the generation dispatch simulation.

To better capture the interaction between Huntly generation and the voltage stability constraint for the WUNI region, we included "generic constraints" for modelling all options. These constraints limit the sum of WUNI circuit flows and Huntly generation. The impact of these generic constraints is to force SDDP to increase generation in Huntly to optimise power transfer within the WUNI region to avoid voltage stability issues.

2 "WUNI2" refers to the second stage of our Waikato and Upper North Island Upgrade programme. We are currently carrying out studies and modelling to confirm the short-list options for WUNI2.

3 The 'southern section' refers to the section of the OTA–WKM A&B lines between Ohinewai and Whakamaru.

In addition, we also applied a "circuit sum constraint", which simply represents the limits of the sum of flows in a defined combination of circuits (e.g., to represent three-terminal circuit contingencies).

1.3 Generation Expansion Planning

Generation expansion planning is the process of forecasting future grid connected generation for a given demand forecast. Generation expansion plans are an input to our generation dispatch simulations.

1.3.1 Least Cost Generation Plans

Our generation expansion modelling focuses on the cost of new generation. Our modelling effectively steps through time (out to 2055 in this case), adding new generation as required to meet forecast demand. It chooses new generation from the generation stack with the overall objective of minimising the cost of electricity over the period being considered. We recognise that there are other factors that play a role in generation investment decisions such as the availability of capital, future views on wholesale electricity prices, the ability of the project to gain consents, power purchase agreements, and retail positions relative to generation. However, our view is that it is reasonable to focus on generation costs on the basis that, although our model may deliver new generation in a different order to the actual electricity market, in the long-run, cost will be the major deciding factor.

1.3.2 Using OptGen

PSR Inc's OptGen modelling software has been used to develop our generation expansion plans. We use PSR's 'Optgen1' algorithm.

Optgen1 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) over the modelling horizon. This is done in two separate stages:

- Operating costs are estimated using the same SDDP algorithm as used for our generation dispatch simulations, with some simplifications to ensure that the model can provide a solution in a reasonable time. Operating costs account for hydro energy variability, hydro inflows uncertainty, and renewable energy variability.
- Operating costs are assessed by a separate algorithm to determine the least cost combination of capital and operating costs.

Optgen1 can be configured with several different possible generation energy or capacity constraints. To align the expansion plans with our expectations of what the market will deliver in the short term, we initially constrain the build to generation projects which developers have committed to, and to those projects which are in the advanced stages of Transpower's connection pipeline. We achieved this by applying a maximum wind and solar installed capacity constraint that varies over time. Specifically, the annual wind and solar build limit is set to 600 MW in 2026, and then grows by 100 MW each year until it reaches 1,000 MW in 2030. From 2030 onwards, the annual wind and solar build cap remains constant at 1,000 MW through to the end of the modelling horizon.

1.3.3 Adjusting the OptGen Generation Expansion Plans

As an additional step, the generation expansion plans from OptGen are adjusted to improve the modelled revenue adequacy of future generation projects. Revenue adequacy is the ratio of expected revenues over expected capital costs. While it can be difficult to model revenue adequacy, particularly in a future dominated by intermittent renewable generation, future generation plants should in general be revenue adequate.

These adjustments are made as a 'post-processing' step, after the OptGen modelling process. Section 3 presents a summary of adjustments made to the original generation expansion plans from OptGen.

The expansion plans are further adjusted to restrict new UNI region plants to prevent circuit overloads as detailed in Section 3.2. The network limits were derived from the results of the 2022 study on Northland Renewable Energy Zones (**Northland REZ**)[4] considering future minor upgrades for the 110 kV and 220 kV lines in Northland.

Lastly, further adjustments are done to ensure that there is no significant difference between North Island and South Island average short run marginal costs (SRMCs), while still ensuring revenue adequacy for all plants built.

1.3.4 How Many Generation Expansion Plans?

We produced generation expansion plans for the three selected 2019 EDGS scenarios. These scenarios are Growth, Reference and Environmental. Using a subset of the 2019 EDGS scenarios simplifies the modelling process while using a wide range of demand and generation inputs. We applied the same generation expansion plan to the counterfactual and factual reconductoring option for both the main case (duplexing) and the sensitivity case (series compensation) for each selected 2019 EDGS scenario. We assumed that:

- future generation development would be unaffected by the circuit constraints on the OTA–WKM A&B lines. Initial testing of this assumption produced generation expansion plans that were not materially different between the counterfactual and factual reconductoring option, and
- that the AC grid is unconstrained.

1.4 Generation Dispatch Simulation

SDDP minimises the electricity system operating costs, accounting for:

- future changes in generation and grid scale batteries – as provided by our generation expansion plans
- future changes to the transmission network for each investment option and the counterfactual
- changes in demand – arising from daily and weekly demand variations through to long term forecast demand growth
- hydro inflow variability and uncertainty

4 Renewable Energy Zones Northland Pilot Concept 2022

- renewable energy variability
- grid scale battery operation, and
- plant operational constraints - including thermal plant unit commitment and hydro plant minimum flow constraints.

SDDP is a well-established model that is widely used in many jurisdictions around the world.

1.4.1 SDDP Policies and Water Values

SDDP generation dispatch simulations are produced in two steps:

1. **Policy evaluation:** In this step SDDP derives a policy, effectively a set of water values for each of New Zealand's major hydro reservoirs. Water values provide the opportunity cost of using or storing water in each hydro reservoir, accounting for risks of both dry year energy shortages and wet year hydro spillage.
2. **Simulation:** Using water values from the policy evaluation, the operation of the electricity system is simulated for a given set of hydro inflow sequences.

SDDP 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 this analysis, consistent with our generation expansion plan approach, we ran policies for each of the three selected 2019 EDGS scenarios. For a given scenario we applied the same policy to the counterfactual and factual reconductoring option, on the basis that decommissioning or reconductoring are unlikely to affect water values for our major hydro generation schemes.

1.4.2 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 renewable generation. However, this will be at the expense of increasing model solve time and model result data storage requirements.

For this analysis, we use an hourly resolution over the modelling horizon to 2055 for generation dispatch simulations.

1.4.3 Hydro Inflow Sequences

SDDP models the optimal dispatch of generation and battery resources across the electricity system using a set of yearly hydro inflow sequences that represent conditions for all modelled hydro generators. In New Zealand, electricity system costs vary significantly with hydro inflows, so capturing this behaviour is a critical part of our generation dispatch simulations.

We use 'synthetic' hydro inflow sequences that are derived from historical hydro inflow records. 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 this analysis, we used:

- **For the policy evaluation step:** 15 and 50 synthetic inflow sequences, respectively, for the ‘backward’ and ‘forward’ phases of the SDDP algorithm.
- **For the simulation step:** 50 synthetic inflow sequences.

1.4.4 Modelling the Transmission Network with SDDP

SDDP uses a simplified, linear, DC load flow model. For this analysis, we introduced the following additional simplifications to our modelling approach:

- Circuit flows are constrained to respect both thermal ratings and other system constraints only for the circuits around the OTA–WKM A&B area. For the rest of the AC grid, circuit flows are unconstrained.
- Only circuits 66 kV and above are included in our grid model.
- AC network losses are ignored during the SDDP generation dispatch simulation. Losses are estimated as a post-processing step (after the model has been run), based on dispatch circuit flows, when estimating benefits. All loads are escalated by an island loss factor (2.85% in the North Island and 3.85% in the South Island[5]) to account for AC losses that must be supplied by generators over and above grid offtake at the GXPs.
- Losses on the HVDC are modelled within SDDP using a linearised approximation of observed HVDC losses.

2 Modelling Assumptions

Demand and generation assumptions for each selected 2019 EDGS scenario are described in Attachment 2. These assumptions form the core of our modelling inputs. Assumptions specific to either the counterfactual or factual reconductoring option are discussed in this Section.

2.1 Transmission Network

The transmission network assumptions for the counterfactual and factual reconductoring option are detailed in Appendix A.

2.2 AC Losses

As outlined in Section 1.4.4, Transpower typically runs SDDP with a lossless AC network to reduce computational complexity. To account for AC system losses, escalation factors are applied to North Island and South Island loads to reflect the expected losses in the AC network in each island. These

[5] See the Assumptions Book paragraph 63 and Section 2.2 of this Attachment for additional information about AC network loss modelling for this analysis.

loss factors are included in the Assumptions Book and are based on analysis of historical system losses.

This simplifying assumption is generally fit for purpose for investment testing as losses typically do not change the merit order of dispatch, and explicitly modelling losses in the market model does not materially influence the results.

However, for this analysis, our comparison of SDDP network flows with network flows from an AC power-flow model that explicitly modelled losses found that assuming a constant loss factor across the North Island leads to an underestimation of AC losses in the WUNI region and a corresponding overestimation in the rest of the North Island (**RNI**) region.

To align losses in SDDP with AC losses, we calibrated the distribution of the North Island losses between the WUNI and RNI regions to reflect the loss patterns observed in the power systems modelling.

To achieve this, we increased the load in the WUNI region by a percentage of its gross load to account for the underestimated losses under the standard approach. We decreased the RNI region's load by the same proportion as we increased the WUNI region load. The values of these factors are based on the scenarios with the highest boundary transfers, which have the most significant impact on network constraint. The equal and opposite adjustments meant that total North Island losses remain unchanged, while a greater share of losses was attributed to the WUNI region. Based on the power system analysis, the applicable percentage adjustments for each option are as follows:

- Option 0a - 4.3%
- Option 1a - 3.8%
- Option 0b - 4.1%
- Option 1b - 3.2%

The calibration results in system states – the combination of circuit flows, bus demand, losses, and generation – that align more closely with power systems modelling and therefore provide a more accurate estimation of benefits.

2.3 Deficit Cost

The cost of deficit (on a $ per MWh basis) is an important input to our generation expansion plans and generation dispatch simulations. Deficit can be thought of as the cost of energy that cannot be supplied by either generation or the transmission network. To account for these characteristics, we assume that the cost of deficit is defined by four incrementally increasing tranches as described in Table 1. Each tranche is for a given amount of deficit, expressed as a percentage of hourly[6] island demand. The first three tranches are intended to represent voluntary demand response measures, such as retailers controlling hot water cylinder demand. The last high value tranche is intended to represent forced curtailment of load (i.e., not supplying electricity), as could occur in a grid emergency.

6 For Optgen1, deficit tranches are specified for the quantity of deficit expressed as a percentage of 'load block' Island demand. Load blocks are groups of similar periods of demand within a given week.

Table 1: Generation expansion plan modelling deficit cost tranches

Deficit as a proportion of Island hourly demand	Cost (2021$)
First 5% of demand	$600 per MWh
Between 5% and 10% of demand	$800 per MWh
Between 10% and 15% of demand	$2,000 per MWh
Greater than 15% of demand	$10,000 per MWh

3 Generation Expansion Plans

This Section describes the generation expansion plans derived for this analysis. These plans use the selected 2019 EDGS scenarios described in Attachment 2 and are an input to the generation dispatch simulations. For a given selected 2019 EDGS scenario, generation expansion plans are the same for all options.

Figure 1 shows cumulative new generation capacity additions and deletions, out to 2055, for the selected 2019 EDGS scenarios (Growth, Environmental, and Reference) based on the final generation expansion plan. New generation build is dominated by wind and solar for all selected 2019 EDGS scenarios. Fossil fuel retirements are covered by grid scale batteries, geothermal or biofuels.

Our assumptions, intended to provide diversity across our generation expansion plans, drive the relatively strong growth in geothermal generation in the Growth scenario, while the other scenarios have greater growth in other plant technologies.

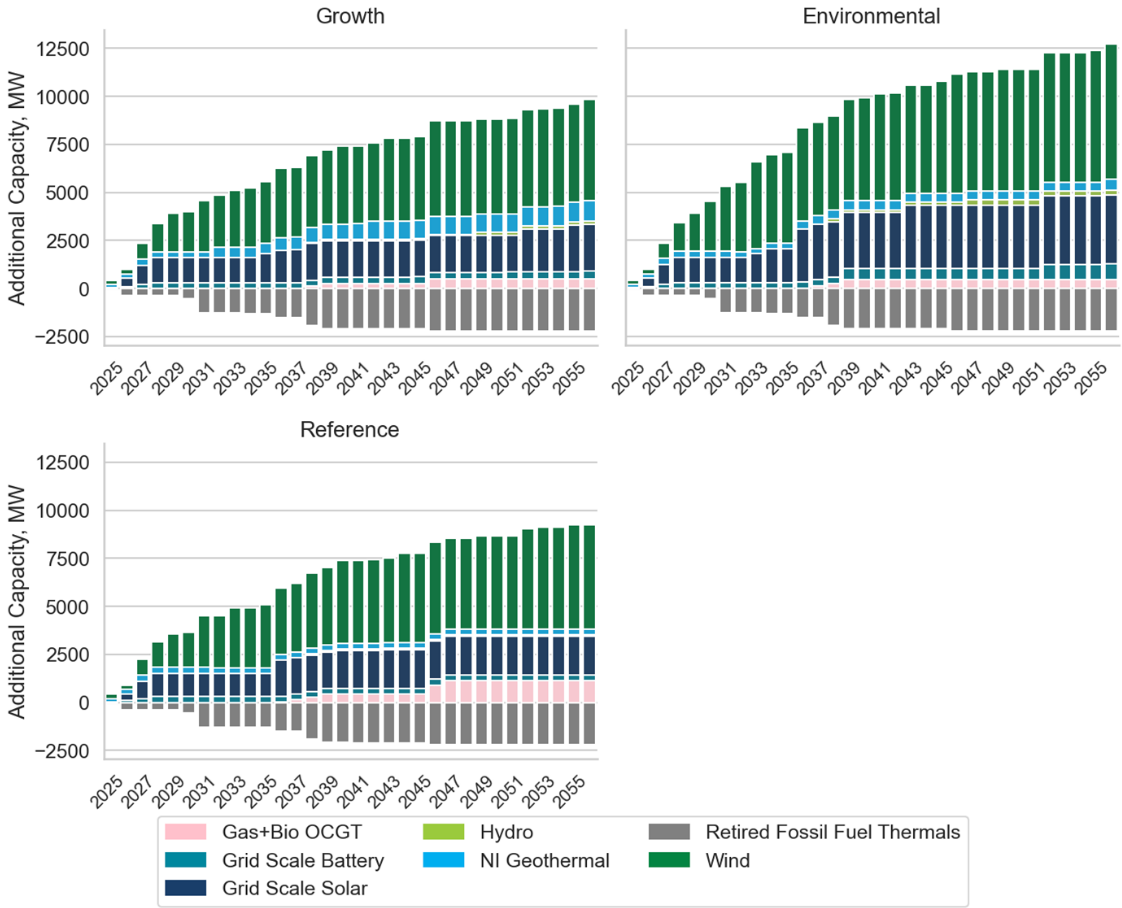


Figure 1: Generation expansion plans, capacity additions, and deletions

3.1 OptGen Adjustments for Revenue Adequacy

We adjusted the OptGen generation expansion plans for the selected 2019 EDGS scenarios to improve revenue adequacy, as described in Section 1.3.3. Only wind and solar generating plants were adjusted in the policy iterations. Other power plant technologies were unchanged.

3.2 Adjustments to Limit Upper North Island Generation

Given that the OptGen runs assume an unconstrained grid, we have adjusted the total capacity of new plants in the UNI region according to the grid capability informed by our Northland REZ study.[7] The study showed that without significant transmission investment, generation north of Huapai 220 kV (HPI220) should be limited to around 440 MW, with an additional 200 MW potentially accommodated at HPI220. The 220 kV circuits connected to the Bream Bay 220 kV (BRB220) and HPI220 bus would require significant upgrades if the existing generation expansion plan (after revenue adequacy adjustments) were implemented without further adjustments. During our analysis for consultation, excess UNI region wind and solar generation were moved to either the

[7] Renewable Energy Zones Northland Pilot Concept 2022

Whakamaru or Bunnythorpe 220 kV (WKM220 or BPE220) buses while excess geothermal generation was moved to the Wairakei 220 kV (WRK220) bus.

For this analysis, the generation expansion plan has been aligned with the modelling we are doing for our WUNI Stage 2 Major Capex Proposal. Since the consultation, we have refined our generation expansion assumptions—specifically by reallocating surplus Northland generation from OptGen to designated alternative plants outside the WUNI region. These replacement plants share the same technology, capacity factor and commissioning date. For example, in the Growth scenario, the final expansion plan includes the plants located in the UNI region as listed in Table 2.

Table 2: Generation expansion plan for Growth scenario after applying the limits in the UNI region

Plant Name	Installed Capacity, MW	Bus	Technology	Status	Build Year
Glenbrook	112	GLN220	NI Process	Existing	-
Kohira_LS	39	KOE110	Grid Scale Solar	Existing	-
Ngawha	25	KOE110	NI Geothermal	Existing	-
Ngawha3	31.5	KOE110	NI Geothermal	Existing	-
Southdown	1	SWN220	Grid Scale Battery	Existing	-
Ruakaka	100	BRB220	Grid Scale Battery	Committed	2025
Glenbrook_2h	100	GLN220	Grid Scale Battery	Committed	2026
Kaiwaikawe	73	MPE110	Wind	Committed	2026
Solar_BRB_1	120	BRB220	Grid Scale Solar	Committed	2026
Ngawha4	25	KOE110	NI Geothermal	Candidate	2031
Ngawha5	25	KOE110	NI Geothermal	Candidate	2035
Solar_GLN_1	200	GLN220	Grid Scale Solar	Candidate	2035
S_HPI220_1	120	HPI220	Grid Scale Solar	Candidate	2037
aB_S119	40	GLN220	Grid Scale Battery	Candidate	2038
W_GLN220	80	GLN220	Wind	Candidate	2038

Figure 2 and Figure 3 compare nationwide projections of installed wind and solar capacities in 2035 and 2055 for the original OptGen results and the adjusted expansion plans after considering revenue adequacy, the UNI limitation and SRMC balance, for each selected 2019 EDGS scenario.

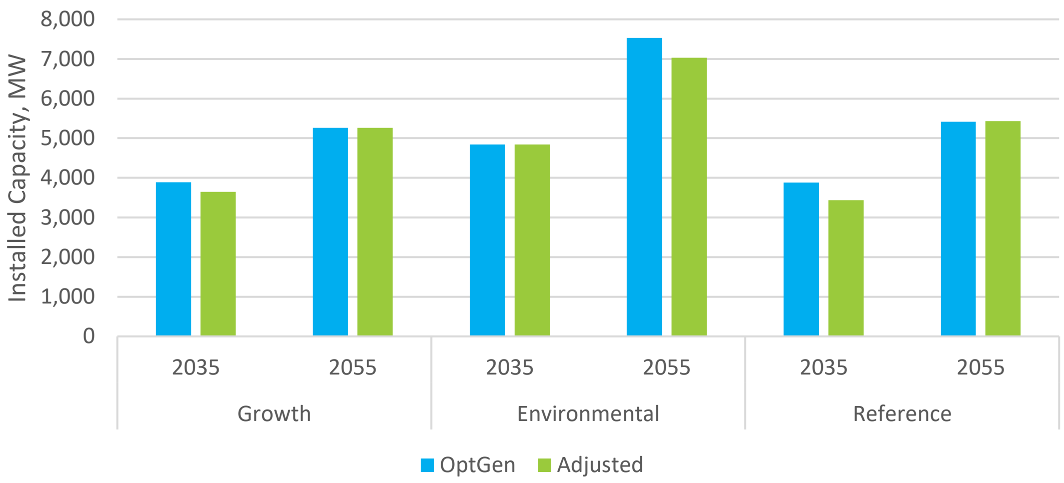


Figure 2: Nationwide wind installed capacity in the final expansion plan

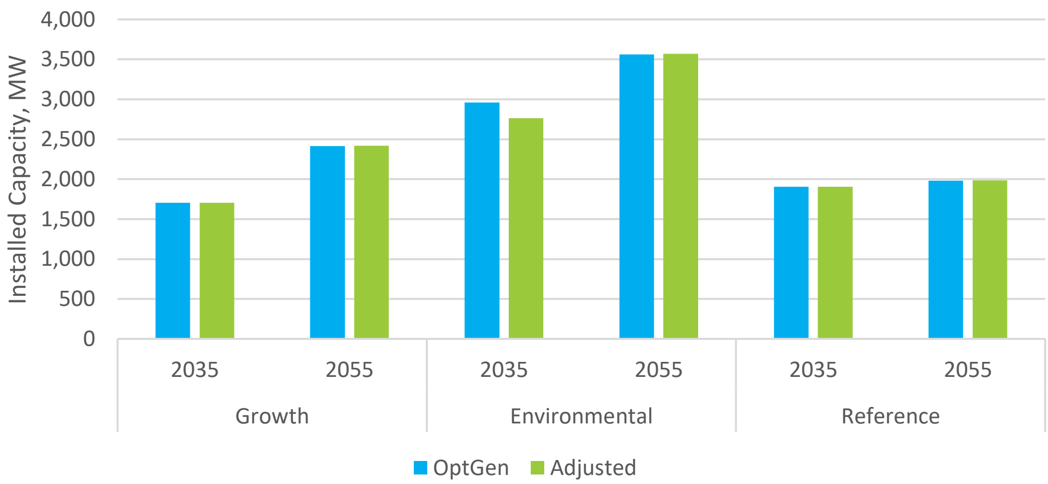


Figure 3: Nationwide solar installed capacity in the final expansion plan

4 Generation Dispatch Simulation Results

This Section provides an overview of our generation dispatch simulation results.

4.1 Generation Dispatch Simulation Benefits

Generation dispatch simulation benefits (dispatch benefits) are calculated as the difference between simulated electricity system costs in the counterfactual and factual reconductoring option (and similarly for the series compensation sensitivity). These benefits are gross in that they exclude the cost of the transmission investment upgrades. Dispatch benefits are calculated for these cost categories:

- **Thermal operating costs:** Including fuel costs, variable operating costs and emission costs.
- **Deficit costs:** Unserved energy costs, using the tranches set out in Section 2.3.
- **AC loss costs:** The treatment of AC grid energy losses, as explained in Section 2.2. Loss costs are estimated using Island SRMC.

There are no generation investment benefits as we are using the same set of generation expansion plans for the counterfactual and factual reconductoring option.

All costs are sourced from dispatch simulation modelling and are averaged over 50 simulated synthetic hydro inflow sequences.

Dispatch benefits broken down by cost category are shown in Table 3 (main case) and Table 4 (sensitivity case) for the selected 2019 EDGS scenarios. Dispatch benefits are net present values over the 2029-2055 period, using a 5 per cent real discount rate, and they are in 2025 dollars.

Table 3: Main case - Dispatch benefits by cost category (2025 present value at 5% discount rate)

Scenario	AC loss benefits, ($m)	Deficit benefits, ($m)	Thermal operating benefits ($m)	Total benefits, ($m)
Growth	54	7	3	64
Environmental	60	1	-1	60
Reference	44	0	1	46

Table 4: Sensitivity case - Dispatch benefits by cost category (2025 present value at 5% discount rate)

Scenario	AC loss benefits, ($m)	Deficit benefits, ($m)	Thermal operating benefits ($m)	Total benefits, ($m)
Growth	223	271	145	640
Environmental	121	145	13	280
Reference	70	4	41	115

Most of the dispatch benefits for all selected 2019 EDGS scenarios are due to the reduced AC losses and deficit costs of the factual reconductoring option relative to the counterfactual for both the main case and sensitivity case. The benefits from AC losses are driven by the availability of the OTA–WKM A&B lines after reconductoring. In the Reference and Environmental scenarios for the main case, the deficit costs and thermal operating costs for the counterfactual and factual reconductoring option are very close. For all selected 2019 EDGS scenarios, there are few deficits and thermal benefits, indicating that the circuit constraints only bind for a very small fraction of time, as shown in Section 4.2.2.

For the sensitivity case, the higher benefits are derived from the binding constraints associated with the counterfactual. The contingency constraint of Brownhill-Whakamaru North-1 (BHL–WKN–1) binds at Brownhill-Pakuranga-2 (BHL–PAK–2), limiting flows for 11.5% of the time. This results in a spring washer effect in the Whakamaru 220 kV bus (WKM220) to Pakuranga 220 kV bus (PAK220) loop. The binding of the BHL–WKN–1 contingency constraint and spring washer effect were not observed for the factual reconductoring option.

The factual reconductoring option reduces deficit costs and increases the quantity of energy that can be served by grid connected generation and the transmission network. Furthermore, having less thermal generation dispatched relative to the counterfactual results in thermal operating benefits.

Dispatch benefits vary substantially by selected 2019 EDGS scenario and between the main case and sensitivity case. The variations between selected 2019 EDGS scenarios are primarily due to the differences in the rate of demand growth and the respective generation expansion plans. However, the variations between cases arise mainly from differences in the ability of the factual reconductoring option to relieve the circuit constraints in each case.

For brevity, we focus on the Growth scenario and the main case. in our discussion of the dispatch simulation results below.

Figure 4 shows the main case Growth scenario dispatch benefits over time for the factual reconductoring option. AC loss, deficit and thermal operating benefits increase over time in line with demand and generation.

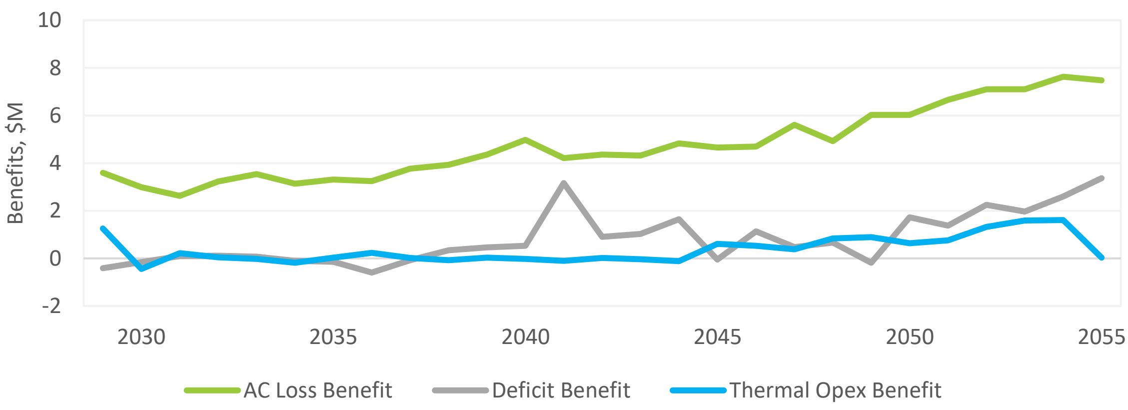


Figure 4: Main case Growth scenario dispatch benefits over time. Benefits are gross, real 2025 dollars

4.2 Circuit Flow

4.2.1 AC Losses

Energy from Whakamaru to Ōtāhuhu and Pakuranga flows in eight major parallel circuits (including the OTA–WKM 1&2 circuits on the OTA-WKM A&B lines). We analysed the AC losses for all the circuits around the OTA–WKM A&B lines. To illustrate, Figure 5 shows the AC energy loss differences for a few selected circuits for the main case factual reconductoring option in the Growth scenario. Although there are disbenefits resulting from the circuit flows on the OTA-WKM A&B lines (i.e. the new OHW–OTA 3&4 circuits which are in service for the factual reconductoring option but not in the counterfactual), the total flows from the other circuits are reduced, offsetting these disbenefits. Therefore, there is an overall net positive benefit for AC losses.

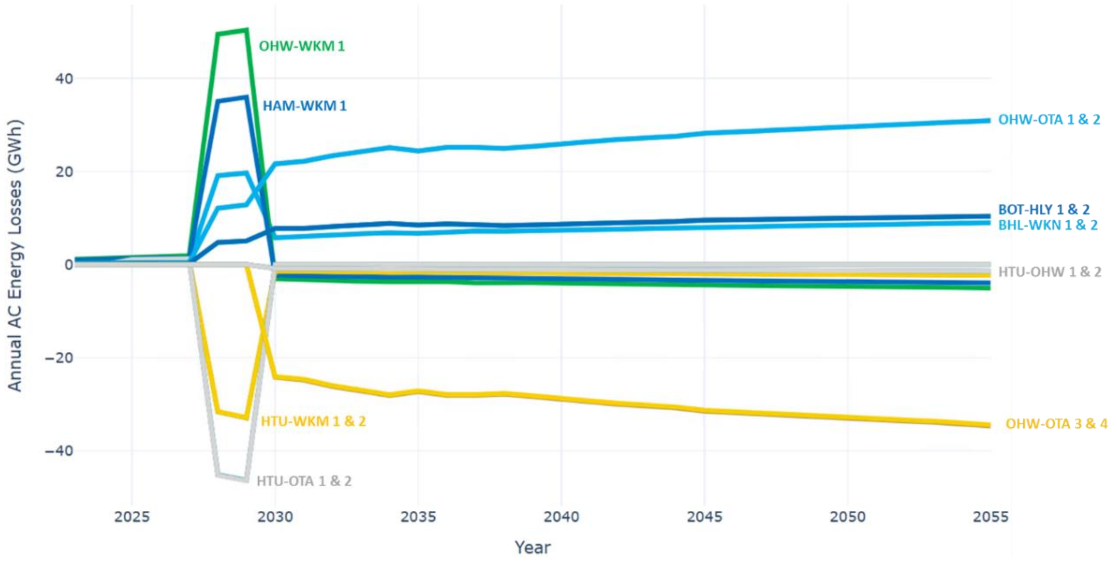


Figure 5: Difference in annual AC energy losses for main case - Growth scenario

4.2.2 Circuit Flow Duration and Constraints

We have applied "generic constraint" equations for voltage stability constraints for all options and a "circuit sum constraint" to represent three-terminal circuit contingencies for the main case factual reconductoring option (Option 1b). These constraints were applied to restrict the sum of circuit flows and prevent voltage issues. In the main case, these constraints bind infrequently for both the factual reconductoring option and in the counterfactual.

To illustrate, Figure 6 ("zoomed in" and combined in Figure 7) shows the flow duration curves from Whakamaru to Ōtāhuhu and Pakuranga for the Growth scenario for the main case counterfactual (Option 0b) and main case factual reconductoring option (Option 1b), considering the circuits and generators included in the generic constraint equations outlined in Appendix A5. The flow duration curves shown are for each hour in 2035 and 2045 for all hydro scenarios. The counterfactual is more constrained than the factual reconductoring option, leading to the dispatch benefits for Option 1b compared to Option 0b . Also, 2045 is more constrained compared to 2035, due to demand growth.

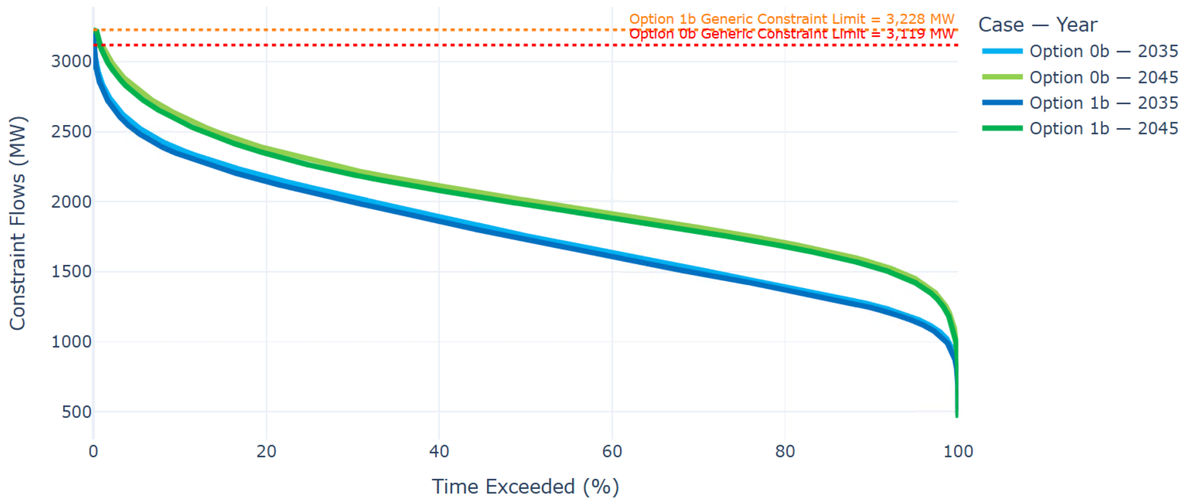


Figure 6: Flow duration curves (2035 and 2045) for circuits and generators in the generic constraints

Figure 7 provides a closer look at 2035 and 2045 for the top 10% of flows, which highlights where the options diverge.

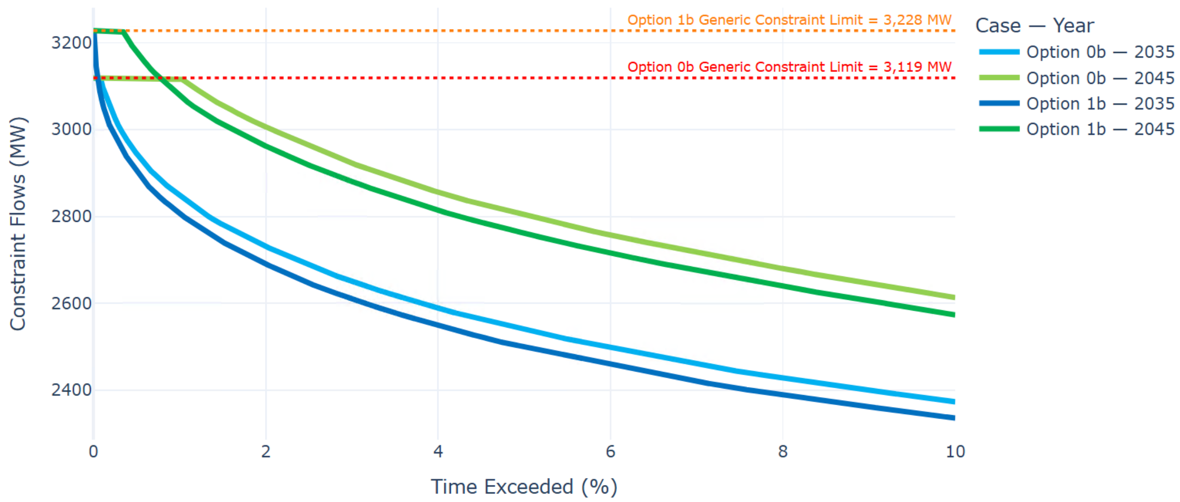


Figure 7: Flow duration curves (2035 and 2045, top 10% of sum of flows) for the circuits and generators in the generic constraints

Considering all the hydro scenarios, for all hours in the modelling horizon, both the counterfactual and factual reconductoring option are constrained for less than 2.4% of the time, as shown in Figure 8. The gap between the lines in these Figures represents a benefit of the factual reconductoring option. This considers the eight major circuits, the Huntly generators, and the additional limitation on loads within the WUNI region as indicated in the generic constraint equations outlined in Appendix A5. The counterfactual is limited to 3,119 MW while the factual reconductoring option is limited to 3,228 MW from 2030 to 2055.

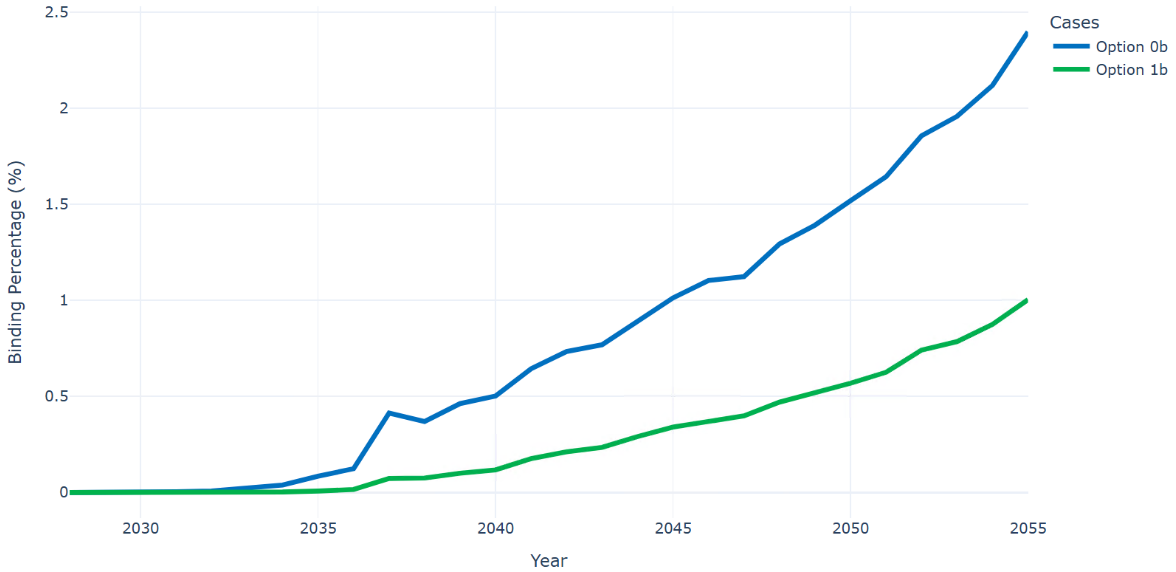


Figure 8: Binding frequency of voltage constraint equations

4.2.3 Post-contingency Analysis

The SDDP model dynamically dispatches generation while ensuring that lines do not overload post contingency. We have applied this feature by modelling contingencies and monitoring other circuits. We have run post contingency analysis to compare how often these contingency-monitor pairs bind between the counterfactual and factual reconductoring option.

In the hourly simulations for the factual reconductoring option, there are only 17 out of 14,414,400[8] (< 0.0001%) instances when the Hamilton-Whakamaru-1 (HAM–WKM–1) contingency binds the Taumarunui – Te Kowhai -1 (TMN–TWH–1) circuit across the full modelling horizon across all the hydro scenarios.

In the counterfactual, the HAM-WKM-1 contingency binds the Ohinewai-Whakamaru-1 (OHW-WKM-1) circuit for 0.11% of the time and the OHW-WKM-1 contingency binds the HAM-WKM-1 circuit for less than 0.005% of the time.

The BHL-WKN-1 contingency does not bind in the main case. However, BHL-PAK-2 binds significantly in the sensitivity case counterfactual - 11.5% for a BHL–WKN–1 contingency.

4.3 Deficit

Figure 9 and Figure 10 show the total deficit averaged over all hydro scenarios.

[8] 168 hours x 52 weeks x 50 hydro scenarios x 33 years (2023 to 2055 modelling horizon)

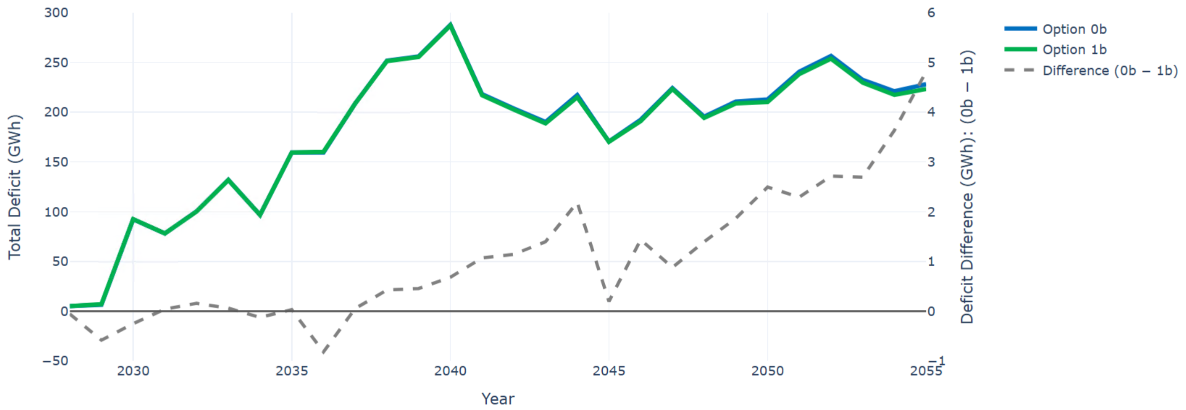


Figure 9: Total deficit, averaged over all hydro scenarios

The factual reconductoring option slightly reduces the energy deficit across the modelling horizon and follows closely the trend of deficit in the counterfactual.

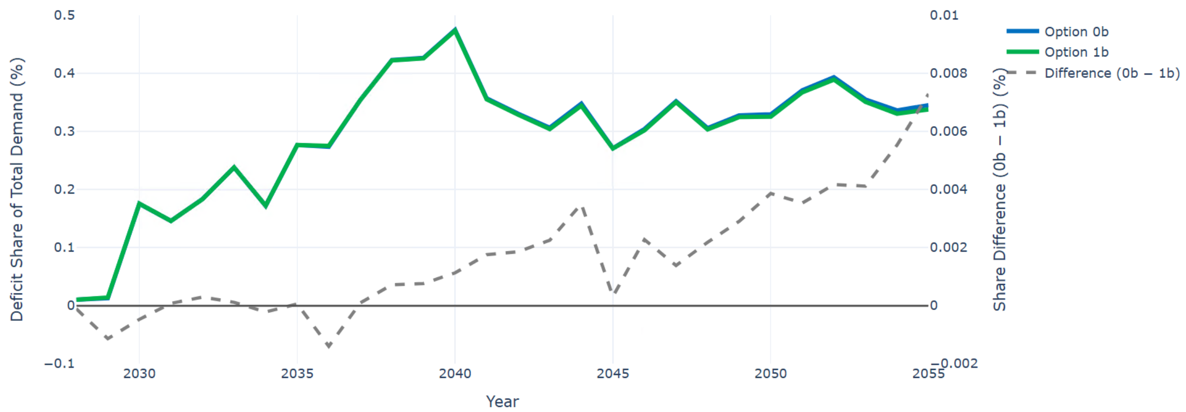


Figure 10: Total deficit as a percentage of total load, averaged over all hydro scenarios

Appendix A: Transmission Network Assumptions

This Appendix provides an overview of the transmission network assumptions used in the modelling.

A1 Existing Transmission Grid

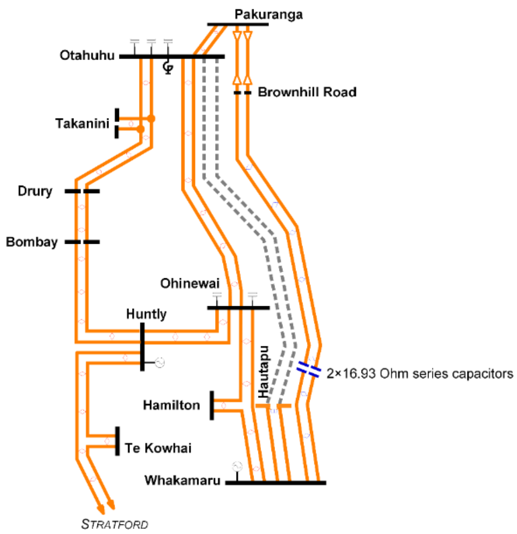
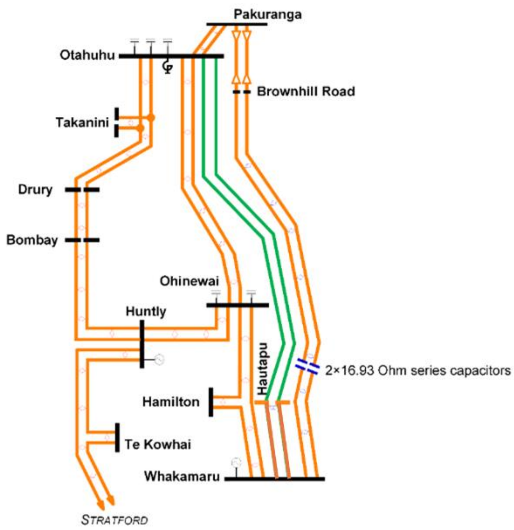
Transmission network properties, including the bus voltage, line resistance, line reactance, and line ratings are from Transpower's asset capability information system. This is the same system used to provide network information from the grid owner to the system operator.

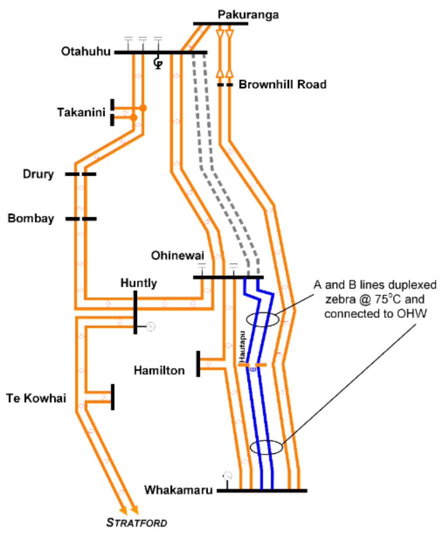
A2 Transmission Options

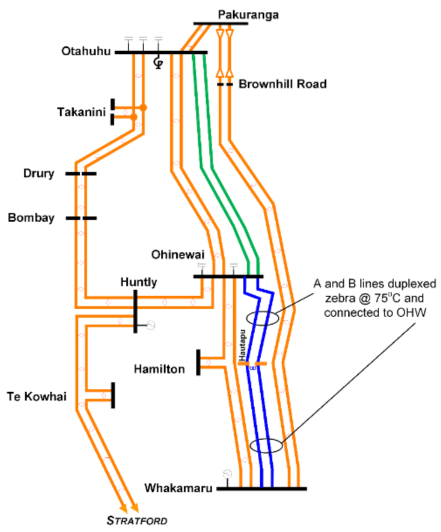
At the time modelling commenced for the OTA–WKM A&B reconductoring application, WUNI2 had not yet identified a preferred option, and there were two likely candidates:

- OTA–WKM Option a or WUNI2 Option 1: a series compensation option. The OTA–WKM modelling for the consultation assumed this for WUNI2. This option is treated as a sensitivity. For the WUNI2 project, this option includes an additional tee at Ōhinewai.
- OTA–WKM Option b or WUNI2 Option 3: duplex the southern section of OTA–WKM A&B lines, and bus into Ōhinewai. This is included in the main case for the proposal.

As the WUNI2 MCP progresses, the preferred upgrade option for WUNI2 may change. However, for the OTA–WKM A&B project, we consider both options are sufficient to assess whether the lines should be reconductored or decommissioned.

<table>
<tr><td colspan="2">Purpose: To understand the benefit of reconductoring the A&B line (HTU – OTA) with WUNI2 upgrades</td></tr>
<tr><td>'Do nothing' configuration (0)</td><td>Reconductored configuration (1)</td></tr>
<tr><td>Option 0a
Remove HTU-OTA + WUNI upgrades
(16.93 Ohm series compensation)

</td><td>Option 1a
Reconductor HTU-OTA + WUNI upgrades
(16.93 Ohm series compensation)

</td></tr>
</table>

<table>
<tr><th>‘Do nothing’ configuration (0)</th><th>Reconductored configuration (1)</th></tr>
<tr><td>
Option 0b
Connect A&B lines at OHW and remove OHW-OTA section + WUNI upgrades
(Otahuhu–Whakamaru duplexing)


</td><td>
Option 1b
Connect A&B lines at OHW and reconductor OHW-OTA section + WUNI upgrades
(Otahuhu–Whakamaru duplexing)


</td></tr>
</table>

Figure 11: Counterfactual & factual grid configurations

WUNI possible investments includes the following:

❖ **Option a: 16.93 Ohm series compensation**

- +/- 150 Mvar STATCOM in Auckland
- 2x16.93 Ohm series compensation at Hangawera Road
- Shunt Capacitors and Dynamic Reactive Plant as required

❖ **Option b: Otahuhu–Whakamaru duplexing**

- +/- 150 Mvar STATCOM in Auckland
- Connect the Otahuhu–Whakamaru A&B line to Ohinewai, duplex the section south of Ohinewai and reconductor the northern section
- Shunt Capacitors and Dynamic Reactive Plant as required

Assumptions on HLY plants from WUNI2 Project

- Generic Constraint with Huntly on the left hand side (LHS): Include Huntly generators with appropriate coefficients on the LHS of generic constraints. This approach reduces instances where the RHS is incorrect due to assumed Huntly generation.

A3 Common Modelled Projects

These modelled projects are applied to all transmission options.

A3.1 Hobson St – Penrose Series Reactor

The Penrose series reactor is presently bypassed. From 2027 the bypass switch is modelled as open. This change is a modelled project common to all development plans, not a committed project. When this occurs, additional developments will be required to alter the power flows in the parallel 110 kV Vector network. This network is presently modelled as a HOB220 and PEN110 load. The sharing between these loads may alter as the parallel path is assumed to be split with a second 220/110 kV transformer installed at Hobson St to provide security to the load there. However, the impact of this change is likely to have a lesser impact on the power flows into the WUNI region, so no change to the model is required. The following table shows the changes to the circuit data. The existing data is provided for comparison.

Table 5: Penrose reactor line upgrade or new line

Circuit	R (Ohm)	X (Ohm)	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Mod Date	Voltage (kV)
HOB-PEN-1 before 2027	0.10	0.97	899	915	899	2024	220
HOB-PEN-1 after 2027	0.10	18.97	572	572	572	2027	220

A3.2 Hautapu GXP + Variable Line Rating (VLR)

The newly commissioned Hautapu GXP is tee-connected to the OTA–WKM A&B lines. This configuration forms a three-terminal circuit, and in the event of an outage on either the northern or southern circuits at Hautapu, the corresponding southern or northern circuit will also trip. The following tables show the changes to the circuit data.

Table 6: Decommissioned Lines

Circuit	Date
OTA-WKM-1	2025
OTA-WKM-2	2025

Table 7: Line upgrade or new line for Hautapu GXP

Circuit	R (Ohm)	X (Ohm)	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Mod Date	Voltage (kV)
HTU-OTA-1	10.49	50.62	362.4	370.4	368.1	2025	220
HTU-OTA-2	10.43	50.35	362.4	370.4	368.1	2025	220
HTU-WKM-1	6.35	30.51	363.5	390.2	372.3	2025	220
HTU-WKM-2	6.38	30.63	363.5	390.2	372.3	2025	220

A3.3 Bombay 110 kV Circuits

Currently, both the BOB–HAM–1 and ARI–BOB–1 circuits are out of service, while BOB–HAM–2 was already decommissioned. It is intended to decommission BOB–HAM–1 and bus ARI–BOB–1 at

Hamilton and decommission the section between BOB and HAM. The following tables show the corresponding changes to the circuit data.

Table 8: Decommissioned Lines

Circuit	Date
BOB-HAM-1	2027
ARI-BOB-1	2027

Table 9: Line upgrade or new line for Bombay

Circuit	R (Ohm)	X (Ohm)	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Mod Date	Voltage (kV)
ARI-HAM-3	10.31	19.69	50.6	61.9	56.5	2027	110

A4 Network Modifications

A4.1 Option 0a: Remove HTU–OTA, with WUNI upgrades including 2x16.93 Ohm series compensation

Table 10: Decommissioning

Circuit	Date
OTA-WKM-1	2025
OTA-WKM-2	2025
HTU-OTA-1	2028
HTU-OTA-2	2028

Table 11: Future Lines

Circuit	R (Ohm)	X (Ohm)	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Mod Date	Voltage (kV)
HTU-OTA-1	10.49	50.62	362.4	370.4	368.1	2025	220
HTU-OTA-2	10.43	50.35	362.4	370.4	368.1	2025	220
HTU-WKM-1	6.35	30.51	363.5	390.2	372.3	2025	220
HTU-WKM-2	6.38	30.63	363.5	390.2	372.3	2025	220

Table 12: Modifications

Circuit	R (Ohm)	X (Ohm)	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Mod Date	Voltage (kV)
BHL-WKN-1 and 2 (Series compensation)	2.74	35.36	1354	1490	1424	2030	220

A4.2 Option 1a: Reconductor HTU–OTA, with WUNI upgrades including 2x16.93 Ohm series compensation

Table 13: Decommissioning

Circuit	Date
OTA-WKM-1	2025
OTA-WKM-2	2025

Table 14: Future Lines

Circuit	R (Ohm)	X (Ohm)	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Mod Date	Voltage (kV)
HTU-OTA-1	10.49	50.62	362.4	370.4	368.1	2025	220
HTU-OTA-2	10.43	50.35	362.4	370.4	368.1	2025	220
HTU-WKM-1	6.35	30.51	363.5	390.2	372.3	2025	220
HTU-WKM-2	6.38	30.63	363.5	390.2	372.3	2025	220

Table 15: Modifications

Circuit	R (Ohm)	X (Ohm)	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Mod Date	Voltage (kV)
BHL-WKN-1 and 2 (Series compensation)	2.74	35.36	1354	1490	1424	2030	220

A4.3 Option 0b: Remove HTU–OTA, with WUNI upgrades including duplexing OTA–WKM A&B lines south of Ohinewai

Table 16: Decommissioning

Circuit	Date
OTA-WKM-1	2025
OTA-WKM-2	2025
HTU-OTA-1	2028
HTU-OTA-2	2028

Table 17: Future Lines

Circuit	R (Ohm)	X (Ohm)	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Mod Date	Voltage (kV)
HTU-OTA-1	10.49	50.61	362.4	370.4	368.1	2025	220
HTU-OTA-2	10.43	50.35	362.4	370.4	368.1	2025	220
HTU-WKM-1	6.35	30.51	363.5	390.2	372.3	2025	220
HTU-WKM-2	6.38	30.63	363.5	390.2	372.3	2025	220
HTU-WKM-1 and 2	2.33	20.61	709.5	780.8	746.1	2030	220
HTU-OHW-1 and 2	1.49	13.22	709.5	780.8	746.1	2030	220

A4.4 Option 1b: Reconductor HTU–OTA, with WUNI upgrades including duplexing OTA–WKM A&B lines south of Ohinewai

Table 18: Decommissioning

Circuit	Date
OTA-WKM-1	2025
OTA-WKM-2	2025
HTU-OTA-1	2030
HTU-OTA-2	2030

Table 19: Future Lines

Circuit	R (Ohm)	X (Ohm)	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Mod Date	Voltage (kV)
HTU-OTA-1	10.49	50.61	362.4	370.4	368.1	2025	220
HTU-OTA-2	10.43	50.35	362.4	370.4	368.1	2025	220
HTU-WKM-1	6.35	30.51	363.5	390.2	372.3	2025	220
HTU-WKM-2	6.38	30.63	363.5	390.2	372.3	2025	220
HTU-WKM-1 and 2	2.33	20.61	709.5	780.8	746.1	2030	220
HTU-OHW-1 and 2	1.49	13.22	709.5	780.8	746.1	2030	220
OHW-OTA-3	6.29	30.51	362.4	370.4	368.1	2030	220
OHW-OTA-4	6.29	30.57	362.4	370.4	368.1	2030	220

A5 Transmission Constraints

A5.1 Common Modelled Transmission Constraints

Since all options share the same conditions before 2027 and their associated constraint equations are identical, the thermal contingencies and the voltage stability constraint equations presented below can be applied to all options. The coefficients for the new generation at Huntly (HLY_{Gen}^{new}) could also be applied to the Rankine units for the period before 2030.

Generic Constraint Equations with HLY at LHS

BHL-PAK-WKN-1 contingency equation-before 2027: Modelled for 2025-2027

-1* HTU-WKM-1 + -1*HTU-WKM-2 + -1*OHW-WKM-1 + -1*HAM-WKM-1 + -1*BHL-WKN-1 + -1* BHL-WKN-2 + -1*HLY-SFD-1 + 1*TMN-TWH-1+ 0.21*E3p + 0.34 * HLY_{Gen}^{new} ≤ 2951 MW

HLY-UN5 contingency equation-before 2027: Modelled for 2025-2027

-1* HTU-WKM-1 + -1*HTU-WKM-2 + -1*OHW-WKM-1 + -1*HAM-WKM-1 + -1*BHL-WKN-1 + -1* BHL-WKN-2 + -1*HLY-SFD-1 + 1*TMN-TWH-1+ 1.14*E3p +0.25 * HLY_{Gen}^{new}≤ 3233 MW

Table 20: Thermal contingency for all options before 2027

Contingency	Monitor 1	Monitor 2	Monitor 3	Monitor 4
BHL-WKN-1	HAM-WKM-1	OHW-WKM-1	BHL-PAK-2	HTU-WKM-1, HTU-OTA-1
HAM-WKM-1	OHW-WKM-1	BHL-PAK-2	HTU-WKM-1, HTU-OTA-1	
OHW-WKM-1	HAM-WKM-1	BHL-PAK-2	HTU-WKM-1, HTU-OTA-1	

Note that the following circuit loadings are managed using variable line ratings. These ratings should be applied where possible:

- Hamilton–Whakamaru–1 (Summer: 760.6 MVA, Shoulder: 780.4 MVA, Winter: 788.8 MVA)
- Ohinewai–Whakamaru–1 (Summer: 760.2 MVA, Shoulder: 765.5 MVA, Winter: 772.4 MVA)
- Hautapu–Otahuhu–1&2 (Summer: 362.4 MVA, Shoulder: 368.1 MVA, Winter: 370.4 MVA)
- Hautapu–Whakamaru–1&2 (Summer: 363.5 MVA, Shoulder: 372.3 MVA, Winter: 390.2 MVA)

A5.2 Option 0a: Remove HTU–OTA, with WUNI upgrades including 2x16.93 Ohm series compensation

The thermal contingencies and the constraint equations for voltage stability limits are presented as follows:

A generic constraint is required to account for the voltage stability limit into the WUNI region. Since it has been assumed that all Rankine units will be decommissioned after 2030, only the coefficients for HLY-UN5 (E3p) and any new generation at Huntly (HLY_{Gen}^{new}) have been considered. The coefficients for the new generation at Huntly could also be applied to the Rankine units for the period before 2030.

Generic Constraint Equations with HLY at LHS

HLY-UN5 contingency equation-2029: Modelled for 2028-2029 -1* HTU-WKM-1 + -1*HTU-WKM-2 + -1*OHW-WKM-1 + -1*HAM-WKM-1 + -1*BHL-WKN-1 + -1* BHL-WKN-2 + -1*HLY-SFD-1 + 1*TMN-TWH-1+ 1.16*E3p + 0.2 * HLY_{Gen}^{new} ≤ 3141 MW
BHL-WKN-1 contingency equation-2029: Modelled for 2028-2029 -1* HTU-WKM-1 + -1*HTU-WKM-2 + -1*OHW-WKM-1 + -1*HAM-WKM-1 + -1*BHL-WKN-1 + -1* BHL-WKN-2 + -1*HLY-SFD-1 + 1*TMN-TWH-1+ 0.15*E3p + 0.21 * HLY_{Gen}^{new} ≤ 2737 MW
BHL-WKN-1 contingency equation-2030: Modelled for 2030-2055 -1* HTU-WKM-1 + -1*HTU-WKM-2 + -1*OHW-WKM-1 + -1*HAM-WKM-1 + -1*BHL-WKN-1 + -1* BHL-WKN-2 + -1*HLY-SFD-1 + 1*TMN-TWH-1+ 0.26*E3p + 0.24 * HLY_{Gen}^{new} ≤ 2862 MW

Table 21: Thermal contingency for Option 0a

Contingency	Monitor 1	Monitor 2	Monitor 3
BHL-WKN-1	HAM-WKM-1	OHW-WKM-1	BHL-PAK-1
HAM-WKM-1	OHW-WKM-1	BHL-PAK-1	BHL-WKN-1
OHW-WKM-1	HAM-WKM-1	BHL-PAK-1	BHL-WKN-1

Note that the following circuit loadings are managed using variable line ratings. These ratings should be applied where possible:

- Hamilton–Whakamaru–1 (Summer: 760.6 MVA, Shoulder: 780.4 MVA, Winter: 788.8 MVA)
- Ohinewai–Whakamaru–1 (Summer: 760.2 MVA, Shoulder: 765.5 MVA, Winter: 772.4 MVA)
- Hautapu–Otahuhu–1&2 (Summer: 362.4 MVA, Shoulder: 368.1 MVA, Winter: 370.4 MVA)
- Hautapu–Whakamaru–1&2 (Summer: 363.5 MVA, Shoulder: 372.3 MVA, Winter: 390.2 MVA)

A5.3 Option 1a: Reconductor HTU–OTA, with WUNI upgrades including 2x16.93 Ohm series compensation

The thermal contingencies and the constraint equations for voltage stability limits are presented as follows:

A generic constraint is required to account for the voltage stability limit into the WUNI region. Since it has been assumed that all Rankine units will be decommissioned after 2030, only the coefficients for HLY-UN5 (E3p) and any new generation at Huntly (HLY_{Gen}^{new}) have been considered. The coefficients for the new generation at Huntly could also be applied to the Rankine units for the period before 2030.

Generic Constraint Equations with HLY at LHS

HLY-UN5 contingency equation-2029: Modelled for 2028-2029 -1* HTU-WKM-1 + -1*HTU-WKM-2 + -1*OHW-WKM-1 + -1*HAM-WKM-1 + -1*BHL-WKN-1 + -1* BHL-WKN-2 + -1*HLY-SFD-1 + 1*TMN-TWH-1+ 1.15*E3p + 0.23 * HLY_{Gen}^{new} ≤ 3408 MW
BHL-WKN-1 contingency equation-2029: Modelled for 2028-2029 -1* HTU-WKM-1 + -1*HTU-WKM-2 + -1*OHW-WKM-1 + -1*HAM-WKM-1 + -1*BHL-WKN-1 + -1* BHL-WKN-2 + -1*HLY-SFD-1 + 1*TMN-TWH-1+ 0.17*E3p +0.28 * HLY_{Gen}^{new} ≤ 3095 MW
BHL-WKN-1 contingency equation-2030: Modelled for 2030-2055 -1* HTU-WKM-1 + -1*HTU-WKM-2 + -1*OHW-WKM-1 + -1*HAM-WKM-1 + -1*BHL-WKN-1 + -1* BHL-WKN-2 + -1*HLY-SFD-1 + 1*TMN-TWH-1+ 0.18*E3p +0.28 * HLY_{Gen}^{new} ≤ 3159 MW

Table 22: Thermal contingency for Option 1a

Contingency	Monitor 1	Monitor 2	Monitor 3
BHL-WKN-1	OHW-WKM-1	BHL-PAK-2	HTU-WKM-1, HTU-OTA-1
HAM-WKM-1	OHW-WKM-1	BHL-PAK-2	HTU-WKM-1, HTU-OTA-1

OHW-WKM-1	HAM-WKM-1	BHL-PAK-2	HTU-WKM-1, HTU-OTA-1

Note that the following circuit loadings are managed using variable line ratings. These ratings should be applied where possible:

- Hamilton–Whakamaru–1 (Summer: 760.6 MVA, Shoulder: 780.4 MVA, Winter: 788.8 MVA)
- Ohinewai–Whakamaru–1 (Summer: 760.2 MVA, Shoulder: 765.5 MVA, Winter: 772.4 MVA)
- Hautapu–Otahuhu–1&2 (Summer: 362.4 MVA, Shoulder: 368.1 MVA, Winter: 370.4 MVA)
- Hautapu–Whakamaru–1&2 (Summer: 363.5 MVA, Shoulder: 372.3 MVA, Winter: 390.2 MVA)

A5.4 Option 0b: Remove HTU–OTA, with WUNI upgrades including duplexing OTA–WKM A&B lines south of Ohinewai

The thermal contingencies and the constraint equations for voltage stability limits are presented as follows:

A generic constraint is required to account for the voltage stability limit into the WUNI region. Since it has been assumed that all Rankine units will be decommissioned after 2030, only the coefficients for HLY-UN5 (E3p) and any new generation at Huntly (HLY_{Gen}^{new}) have been considered. The coefficients for the new generation at Huntly could also be applied to the Rankine units for the period before 2030.

Generic Constraint Equations with HLY at LHS

HLY-UN5 contingency equation-2029: Modelled for 2028-2029 -1* HTU-WKM-1 + -1*HTU-WKM-2 + -1*OHW-WKM-1 + -1*HAM-WKM-1 + -1*BHL-WKN-1 + -1* BHL-WKN-2 + -1*HLY-SFD-1 + 1*TMN-TWH-1+ 1.16*E3p + 0.2 * HLY_{Gen}^{new} ≤ 3141 MW
BHL-WKN-1 contingency equation-2029: Modelled for 2028-2029 -1* HTU-WKM-1 + -1*HTU-WKM-2 + -1*OHW-WKM-1 + -1*HAM-WKM-1 + -1*BHL-WKN-1 + -1* BHL-WKN-2 + -1*HLY-SFD-1 + 1*TMN-TWH-1+ 0.15*E3p + 0.21 * HLY_{Gen}^{new} ≤ 2737 MW
BHL-WKN-1 contingency equation-2030: Modelled for 2030-2055 -1* HTU-WKM-1 + -1*HTU-WKM-2 + -1*OHW-WKM-1 + -1*HAM-WKM-1 + -1*BHL-WKN-1 + -1* BHL-WKN-2 + -1*HLY-SFD-1 + 1*TMN-TWH-1+ 0.26*E3p + 0.36 * HLY_{Gen}^{new} ≤ 3119 MW

HLY-UN5 contingency equation-2030: Modelled for 2030-2055

-1* HTU-WKM-1 + -1*HTU-WKM-2 + -1*OHW-WKM-1 + -1*HAM-WKM-1 + -1*BHL-WKN-1 + -1* BHL-WKN-2 + -1*HLY-SFD-1 + 1*TMN-TWH-1+ 1.11*E3p +0.3 * HLY_{Gen}^{new} ≤ 3413 MW

Table 23: Thermal contingency for Option 0b

Contingency	Monitor 1	Monitor 2	Monitor 3
BHL-WKN-1	HAM-WKM-1	BHL-PAK-2	HTU-WKM-1, HTU-OHW-1
HAM-WKM-1	OHW-WKM-1	BHL-PAK-2	HTU-WKM-1, HTU-OHW -1
OHW-WKM-1	HAM-WKM-1	BHL-PAK-2	HTU-WKM-1, HTU-OHW -1

Note that the following circuit loadings are managed using variable line ratings. These ratings should be applied where possible:

- Hamilton–Whakamaru–1 (Summer: 760.6 MVA, Shoulder: 780.4 MVA, Winter: 788.8 MVA)
- Ohinewai–Whakamaru–1 (Summer: 760.2 MVA, Shoulder: 765.5 MVA, Winter: 772.4 MVA)

A5.5 Option 1b: Reconductor HTU-OTA, with WUNI upgrades including duplexing OTA–WKM A&B lines south of Ohinewai

The thermal contingencies and the constraint equations for voltage stability limits are presented as follows:

A generic constraint is required to account for the voltage stability limit into the WUNI region. Since it has been assumed that all Rankine units will be decommissioned after 2030, only the coefficients for HLY-UN5 (E3p) and any new generation at Huntly (HLY_{Gen}^{new}) have been considered. The coefficients for the new generation at Huntly could also be applied to the Rankine units for the period before 2030.

Generic Constraint Equations with HLY at LHS

HLY-UN5 contingency equation-2029: Modelled for 2028-2029

-1* HTU-WKM-1 + -1*HTU-WKM-2 + -1*OHW-WKM-1 + -1*HAM-WKM-1 + -1*BHL-WKN-1 + -1* BHL-WKN-2 + -1*HLY-SFD-1 + 1*TMN-TWH-1+ 1.15*E3p + 0.23 * HLY_{Gen}^{new} ≤ 3408 MW

BHL-WKN-1 contingency equation-2029: Modelled for 2028-2029

-1* HTU-WKM-1 + -1*HTU-WKM-2 + -1*OHW-WKM-1 + -1*HAM-WKM-1 + -1*BHL-WKN-1 + -1* BHL-WKN-2 + -1*HLY-SFD-1 + 1*TMN-TWH-1+ 0.17*E3p +0.28 * HLY_{Gen}^{new} ≤ 3095 MW

BHL-WKN-1 contingency equation-2030: Modelled for 2030-2055 -1* HTU-WKM-1 + -1*HTU-WKM-2 + -1*OHW-WKM-1 + -1*HAM-WKM-1 + -1*BHL-WKN-1 + -1* BHL-WKN-2 + -1*HLY-SFD-1 + 1*TMN-TWH-1+ 0.23*E3p + 0.31 * HLY_{Gen}^{new} ≤ 3228 MW
HLY-UN5 contingency equation-2030: Modelled for 2030-2055 -1* HTU-WKM-1 + -1*HTU-WKM-2 + -1*OHW-WKM-1 + -1*HAM-WKM-1 + -1*BHL-WKN-1 + -1* BHL-WKN-2 + -1*HLY-SFD-1 + 1*TMN-TWH-1+ 1.11*E3p +0.26 * HLY_{Gen}^{new} ≤ 3496 MW

Table 24: Thermal contingency for Option 0b

Contingency	Monitor 1	Monitor 2	Monitor 3	Monitor 4
BHL-WKN-1	OHW-OTA-3	HAM-WKM-1	BHL-PAK-2	HTU-WKM-1, HTU-OHW-1
HAM-WKM-1	OHW-WKM-1	BHL-PAK-2	HTU-WKM-1, HTU-OHW-1	OHW-OTA-3
OHW-WKM-1	HAM-WKM-1	BHL-PAK-2	HTU-WKM-1, HTU-OHW-1	OHW-OTA-3
OHW-OTA-1	OHW-OTA-3	OHW-OTA-4	OHW-OTA-2	

Since SDDP is not capable of modelling three-terminal circuit contingencies, the following constraint equations can be used as an alternative to represent the thermal contingency for the following cases from 2030:

Contingency: HTU–OHW–WKM–1 or 2 and Constraint: HAM–WKM–1

- Winter:

  -1* HAM-WKM-1 - 0.23*HTU-WKM-1 ≤ 750 MW

- Shoulder:

  -1* HAM-WKM-1 - 0.23*HTU-WKM-1 ≤ 744 MW

- Summer:

  -1* HAM-WKM-1 - 0.23*HTU-WKM-1 ≤ 729 MW

Note that the following circuit loadings are managed using variable line ratings. These ratings should be applied where possible:

- Hamilton–Whakamaru–1 (Summer: 760.6 MVA, Shoulder: 780.4 MVA, Winter: 788.8 MVA)
- Ohinewai–Whakamaru–1 (Summer: 760.2 MVA, Shoulder: 765.5 MVA, Winter: 772.4 MVA)

- Ohinewai–Otahuhu–3 & 4 (Summer: 362.4 MVA, Shoulder: 368.1 MVA, Winter: 370.4 MVA)

TRANSPOWER

TRANSPOWER.CO.NZ