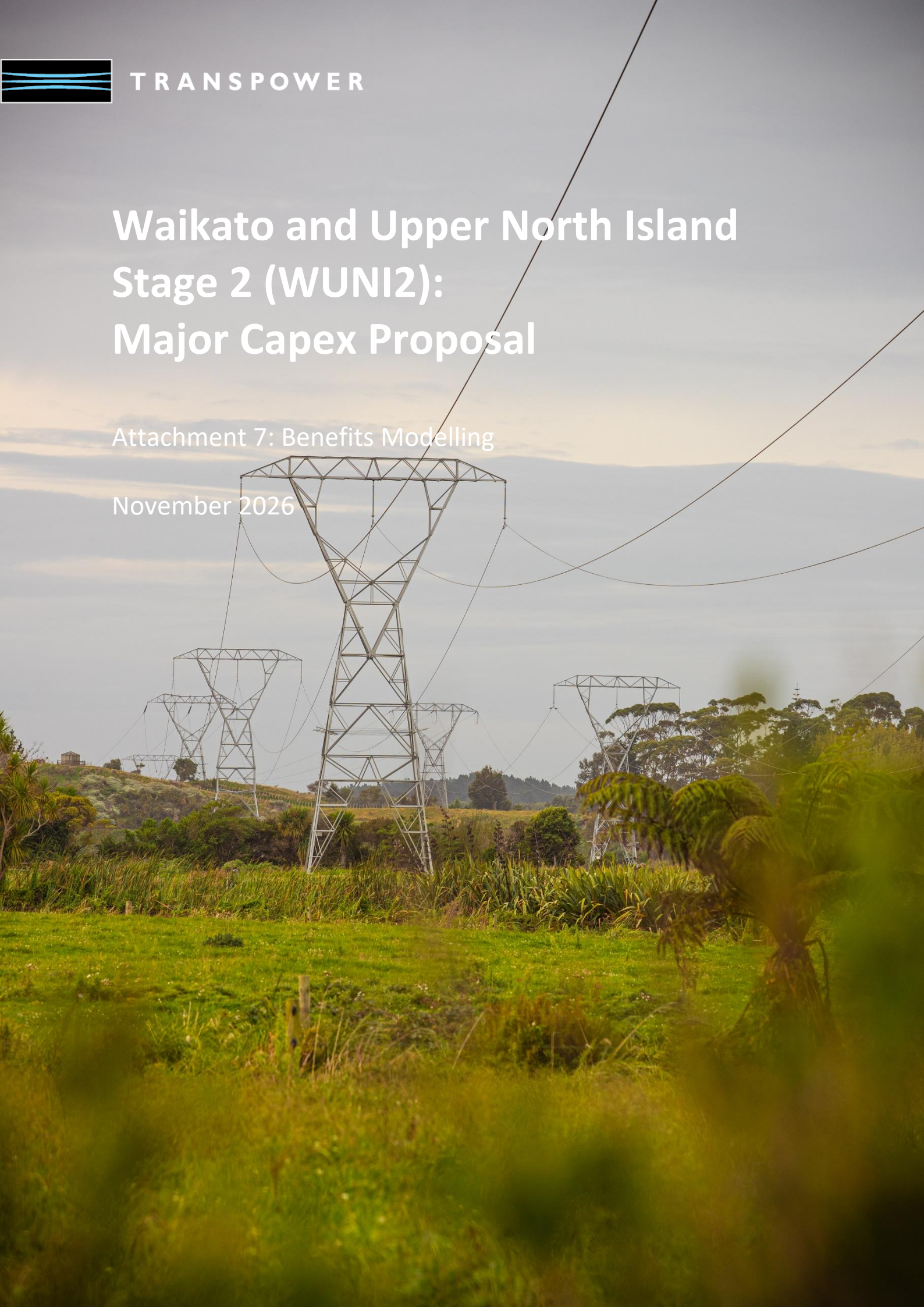
TRANSPOWER

Waikato and Upper North Island Stage 2 (WUNI2): Major Capex Proposal

Attachment 7: Benefits Modelling

November 2026



Purpose

This Attachment forms part of our Waikato and Upper North Island (**WUNI**) Stage 2 Major Capex Proposal (**MCP**). This Attachment describes how we have calculated the generation dispatch benefits of the investment options for Stage 2 of the WUNI Upgrade major capex project (**Stage 2**) and potential future stages, using models of the New Zealand electricity system. The benefits are a key element of the investment test in Schedule D of the Capex IM[1] (**Investment Test**).

[1] Commission, Transpower Capital Expenditure Input Methodology [2012] NZCC 2 (**Capex IM**).

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1 Benefits modelling approach

This section describes the approach used in our analysis to model and calculate the generation dispatch benefits of the investment options for Stage 2 and potential future stages of the WUNI Upgrade major capex project.

We use models of the New Zealand electricity system to calculate the benefits of investment options to address the investment need.

The main components of our analysis are:

- **Power system analysis:** Conducted by our system planning team, this analysis helps determine the investment need, investment options and the timing of each investment option. It also provides inputs into our generation dispatch simulation modelling, such as upgraded circuit capacities for each investment option.
- **Generation expansion planning:** We find the lowest cost combination of new generation projects required to meet our forecast demand. For this analysis we use PSR Inc's OptGen software. Like the demand scenarios, we developed generation expansion plans for a subset of MBIE's 2024 Electricity Demand and Generation Scenarios (**EDGS**), with variations.[2] The selected scenarios are the Growth, Reference and Environmental scenarios – limiting the modelling to these three scenarios simplified the modelling while covering a wide range of demand and generation inputs. We did not use the Constraint scenario due to its unreasonably low level of long-term growth. Demand in the Innovation scenario is within the range of the selected scenarios and therefore adds limited additional insights. The original OptGen expansion plans for each selected scenario are modified to improve revenue adequacy of generation build.
- **Generation dispatch simulations:** These simulations estimate electricity system operating costs for the counterfactual and the investment options. For this we use PSR Inc's SDDP software with generation dispatch simulations developed for the selected scenarios.

Our counterfactual is a base case in which no transmission investment is made, resulting in a high risk of unserved energy. While this counterfactual does not address the investment need and we do not consider it to be good electricity industry practice, we include it to demonstrate the electricity market benefits of the investment options.

Our modelling provides estimates of electricity system costs for the counterfactual and the investment options. The electricity market benefits of a transmission option are calculated as the difference between the system costs of the investment option and the system costs of the counterfactual.

[2] See Attachment 3 for further information about the selected scenarios.

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. An overview of these inputs follows.

2.1 Timing of transmission network changes

Power system analysis is used to determine the timing of each investment option's transmission upgrades. Transmission investment is timed so that loads on existing transmission assets do not exceed their current capabilities prior to being replaced or upgraded.

As explained in Attachments 2 and 4, the final short-listed development plans are still based on the prudent peak load forecast as presented in the short list consultation (Environmental scenario, based on 2019 EDGS) but with updated load limits. However, the modelling of the electricity market benefits as presented in this Attachment uses a peak load forecast based on 2024 EDGS.

2.2 Specifications of transmission network changes

Power system analysis is also used to help determine new and upgraded circuit capacities and electricity characteristics for each investment option's transmission upgrades.

Long-term development plans are modelled in Power Factory to resolve the investment need using combinations of:

- upgrading existing assets
- reconfiguring existing assets
- adding new assets, and/or
- adding an operational procedure, such as a special protection scheme, to address part or all of the system need.

2.3 Transmission network constraints

Transmission network constraints are also derived from power system analysis and defined for all investment options. These constraints ensure flows in and through the WUNI region reflect actual market conditions. Constraints are applied to limit circuit flows to ensure that circuit thermal ratings are respected in the event of a contingency (failure of a line or transformer) or to avoid voltage stability issues. These constraints may limit flows substantially below the thermal rating of a circuit.

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, cannot be modelled explicitly in the generation dispatch simulation. These limits must be produced by power systems analysis in the form of linear constraints where sums of circuit flows and/or grid injections are forced to satisfy specified limits.

To better capture the interaction between Huntly generation and the voltage stability constraint for the WUNI region, we included constraints that limit the sum of WUNI boundary transfer and Huntly generation. The impact of these generic constraints is to force SDDP to increase WUNI generation, particularly at Huntly to optimise power transfer within the WUNI region to avoid voltage stability issues.

We also applied a constraint that limits of the sum of flows in a defined combination of circuits to represent three-terminal circuit contingencies.

2.4 Transmission network assumptions

Transmission network assumptions for the counterfactual and each investment option are detailed in Appendix A.

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.

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), building 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, in the long-run, electricity cost will be the major deciding factor.

3.1.1 Using OptGen

PSR Inc's OptGen modelling software has been used to develop our generation expansion plans. PSR's 'Optgen1' 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) over the modelling horizon. This is achieved through an iterative process involving two linked stages:

1. Operating costs are estimated using the same SDDP algorithm as used for our generation dispatch simulations. Although we make some simplifications to ensure that the model run time is practical, we do account for hydro inflow uncertainty and renewable energy variability.
2. The generation expansion plan is then adjusted to reduce the total system cost, which includes both the capital cost of new generation capacity and operating cost.

The updated plan is re-evaluated (stage 1), and the process repeated until an approximate least-cost outcome is achieved. Optgen1 can be configured with several 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 that developers have committed to, and to those projects that are in the advanced stages of Transpower's connection pipeline. Our generation expansion simulation starts in 2025. OptGen requires the capital cost and location of each potential new generating station to determine which stations to build over the standard method calculation period. We used the cost and generation stack

assumptions listed in Section 2.3.8 and Appendix F of the BBC Assumptions Book v3.0 (**Assumptions Book**).[3]

3.2 How many generation expansion plans?

We produced generation expansion plans for the selected scenarios (Growth, Reference and Environmental).

We consider that this investment is unlikely to materially influence the location of future generation. Therefore, consistent with paragraph 205 of the Assumptions Book, the AC grid is unconstrained in OptGen, so that for each scenario the resulting expansion plans are the same for the counterfactual and all investment options.

3.3 OptGen adjustments for revenue adequacy

We adjusted the OptGen generation expansion plans for the selected scenarios to improve revenue adequacy. 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. The existing and committed generation is left untouched, but future generation is shifted in time through an iterative process with the goal of achieving revenue adequacy over a 10-year period. Adjustments are done in such a way as to introduce no significant difference between North Island and South Island average short run marginal generation costs, while still ensuring revenue adequacy remains within reasonable modelling tolerances. Thermal peaking, geothermal, wind and solar generating plants were adjusted in the policy iterations. No adjustments were made for battery energy storage systems (**BESS**).

[3] Assumptions Book. The Assumptions Book is relevant to calculating and adjusting benefit-based charge allocations under the transmission pricing methodology (**TPM**) and is not binding in the Investment Test context. However, the Assumptions Book contains some useful modelling inputs and assumptions we choose to use in the Investment Test to maximise consistency between the calculation of electricity market benefits (in the Investment Test) and net private benefits (under the TPM).

4 Generation dispatch simulation

SDDP dispatches available generation so as to minimise the electricity system operating costs, accounting for:

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

4.1 SDDP policies and water values

SDDP generation dispatch simulations are produced in two steps:

- **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.
- **Simulation:** Using the 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. One policy was produced for each selected scenario and applied across the counterfactual and all investment options within that scenario, as the differences between investment options were not expected to materially affect water values for the major hydro schemes.

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 full modelling horizon to 2055 for generation dispatch simulations.

4.3 Hydro inflow sequences

SDDP simulates the dispatch of generation and BESS resources across the electricity system for a defined 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 and 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. SDDP creates these sequences by considering the relationships between historical hydro plant inflows and the time of year, and the relationships between different hydro plant inflows.

For this analysis, we used:

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

4.4 Modelling the transmission network with SDDP

SDDP uses a simplified, linear, DC load flow model. For this analysis, we also make the following further simplifications:

- AC circuit flows are constrained to respect both thermal ratings and other circuit constraints only for the interface between the rest of the North Island (**RNI**) and the WUNI region. Where appropriate, different thermal ratings and constraints are applied for the counterfactual and each investment option. The constraints and thermal ratings for this analysis are described in Appendix A. In the short list consultation modelling, all investment options alleviated the voltage stability constraint to the extent that it never bound, so to save time the voltage constraints are only modelled in the counterfactual. 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 not treated explicitly in the SDDP generation dispatch simulation. To account for the extra generation required to counteract average losses, all loads are escalated by an island loss factor (2.85% in the North Island and 3.85% in the South Island).[4] To estimate electricity market benefits, losses are estimated as a post processing

[4] See the Assumptions Book paragraph 63 and section 4.5 of this Attachment for additional information about AC network loss modelling for this analysis.

step (after the model has been run), based on dispatch circuit flows and North Island short run marginal generation costs.

- Losses on the HVDC link are modelled within SDDP using a linearised approximation of observed HVDC losses.

4.5 AC losses

As outlined in Section 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 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 RNI region.

To align losses in SDDP, 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. This was done via a negative power injection at OTA220. We decreased the RNI region's load by the same amount as we increased the WUNI region load using an equal and opposite power injection. 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 mean that total North Island losses remain unchanged, while a greater share of losses is attributed to the WUNI region. Based on the power systems modelling, the applicable percentage adjustments for the counterfactual and each investment option are as follows:

- Counterfactual: 6.06%
- Option 2: 4.02%
- Option 3: 4.53%
- Option 4b: 4.53%

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 electricity market benefits.

4.6 Deficit cost

The cost of deficit (on a $ per MWh basis) is an important input to our generation expansion plan and generation dispatch simulation modelling. 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 specified in section 2.3.7 of the Assumptions Book for the selected scenarios:

- First 2.25% of demand: $700/MWh[5]
- Between 2.25% and 4.5% of demand: $950/MWh
- Between 4.5% and 9.5% of demand: $4,000/MWh
- Greater than 9.5% of demand: $21,000/MWh.

[5] These values and all other monetary model inputs are in real 2025 dollars as per the Assumptions Book. The outputs that are used in the Investment Test are inflated to real 2026 dollars in a post-processing step to be consistent with the cost estimates and the present value calculations.

5 Deviations from Assumptions Book

We applied the assumptions in section 2.3.8 of the Assumptions Book, with four exceptions:

1. Optgen: Aligning with our Northland REZ study[6], we applied a maximum capacity build constraint of 440 MW in Northland and 640 MW across Northland and Huapai to reflect export constraints from the Northland region. The generation stack includes a large amount of generic capacity in this region, but a significant amount of transmission investment would be required to allow it to be exported south.

2. Optgen: We applied a maximum build constraint of 750 MW per year for solar, 500 MW per year for wind, and 200 MW per year for geothermal because we found that without these constraints an unrealistic quantity of generation was being built in the early years of the calculation period.

3. Optgen: We updated our committed generation stack to include several new projects. Those projects are listed in Attachment 3 (section 3.2 and Appendix C).

4. SDDP: Wind and solar generation profiles for existing, committed and new generation were derived using historical wind flow and solar irradiance data from 1980 to 2024, rather than the 1980–2017 period specified in section 2.3.4.6 of the Assumptions Book. This incorporates the most recent available historical wind and solar data and provides a longer historical record on which to develop the generation profiles.

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6 Results

6.1 Expansion plans for WUNI2

Figure 1 shows cumulative new generation capacity additions and retirements for the selected scenarios (Growth, Environmental, and Reference) based on the final generation expansion plan. For a given scenario, generation expansion plans are the same for all investment options. New generation build is dominated by wind and solar for all selected scenarios. Fossil fuel retirements are covered by grid scale BESS, geothermal or biofuels. In addition, new hybrid gas-bio OCGT plants are built at Huntly and Ōtorohanga in all scenarios around the time of Huntly retirements. A (bio)gas/(bio)diesel reciprocating engine is also built in the Environmental and Growth scenarios.

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 solar or biogas thermal.

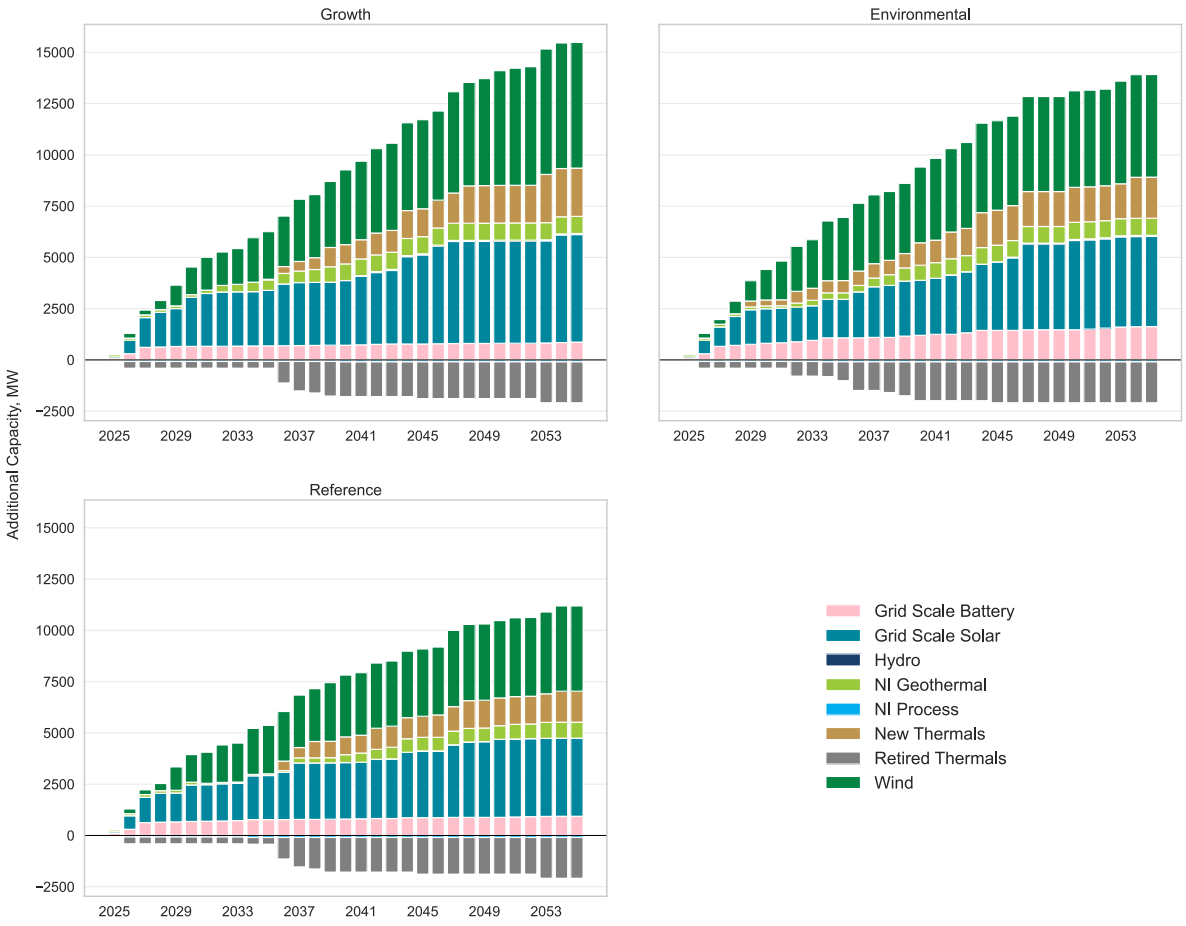


Figure 1: Generation expansion plans, capacity additions and retirements

6.2 Generation dispatch simulation results

This section provides an overview of our generation dispatch simulation results. Benefits derived from our generation dispatch simulations are combined with all other electricity market benefits and costs in the Investment Test (Attachment 5).

6.2.1 Generation Dispatch Simulation Benefits

Generation dispatch simulation benefits (dispatch benefits) are calculated for each investment option by finding the difference between simulated electricity system costs for that option and the counterfactual. These benefits are gross in that they exclude the cost of transmission investment upgrades. Dispatch benefits are calculated for these cost categories:

- **Thermal operating costs:** Including fuel costs, variable operating costs and emission costs.
- **AC loss costs:** The treatment of AC grid energy losses, as explained in Section 4.5. Loss costs are estimated using island short run marginal generation costs.
- **Deficit costs:** Unserved energy costs, using the tranches referenced in Section 4.6.

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

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

Dispatch benefits, broken down by costs category, are shown in the tables below for the selected scenarios. Dispatch benefits are net present values (in 2026 dollars) over the 2034 to 2055 calculation period,[7] with a 5% real discount rate.

Dispatch benefits for all investment options and all market scenarios are mainly due to reductions in AC loss costs relative to the counterfactual. There are also benefits due to the reduction of deficit.

Dispatch benefits vary substantially by selected scenario. These variations are primarily due to the differences in the rate of demand growth and the respective generation expansion plans.

Table 1: Environmental scenario, dispatch benefits by category (present value, 5% discount rate)

Option	Thermal operating benefits ($m)	AC loss benefits, ($m)	Deficit benefits, ($m)	Total benefits, ($m)
Option 2	102	284	4	390
Option 3	102	252	4	359
Option 4b	101	273	4	379

[7] See Attachment 5 for an explanation for the calculation period start and end dates.

Table 2: Growth scenario, dispatch benefits by category (present value, 5% discount rate)

Option	Thermal operating benefits ($m)	AC loss benefits, ($m)	Deficit benefits, ($m)	Total benefits, ($m)
Option 2	195	374	59	629
Option 3	194	338	61	594
Option 4b	195	362	62	620

Table 3: Reference scenario, dispatch benefits by category (present value, 5% discount rate)

Option	Thermal operating benefits ($m)	AC loss benefits, ($m)	Deficit benefits, ($m)	Total benefits, ($m)
Option 2	30	198	-1	228
Option 3	30	174	-2	202
Option 4b	30	190	-1	219

As discussed in the Overview document and Attachment 5, Option 4b is our preferred investment option (the proposed investment). We focus on the counterfactual and Option 4b in our discussion of the dispatch simulation results below.

Figure 2 shows the discounted dispatch benefits of Option 4b over time for the selected scenarios. AC loss benefits are significant for the duration of the calculation period and are the dominant source of dispatch benefit. Reduction in thermal operating costs becomes apparent from 2039 in the Growth and Environmental scenarios, when the voltage stability constraint starts to bind more frequently due to demand growth. For the Growth scenario, thermal operating benefits approach the magnitude of AC loss benefits at the end of the calculation period horizon. The higher demand in the Growth scenario also results in significant benefits due to the alleviation of deficit costs, peaking in 2052.

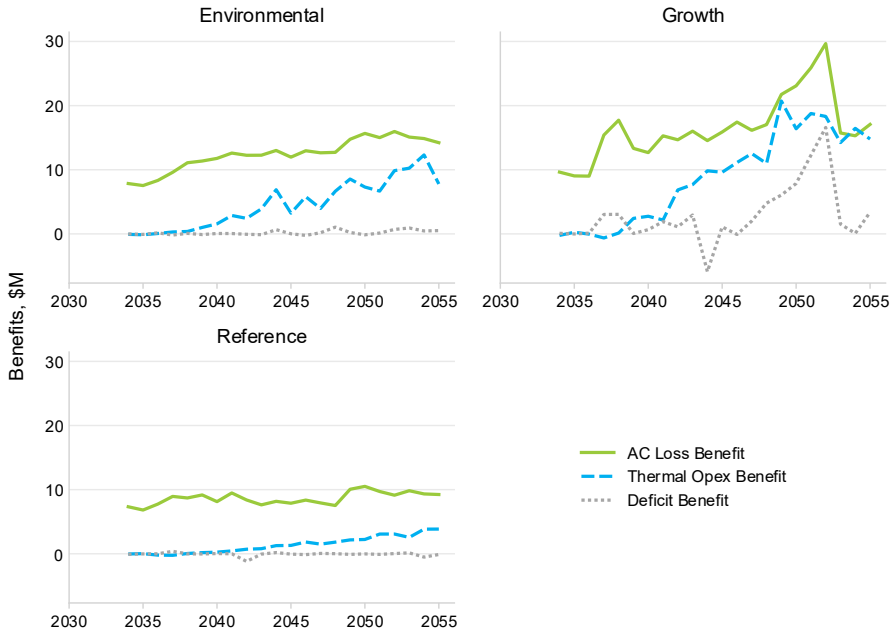


Figure 2: Dispatch benefits over time for Option 4b (present value, 5% discount rate)

6.2.2 Circuit Flow

We have applied constraint equations, which incorporate WUNI boundary flows and Huntly generation, to represent voltage stability constraints in the counterfactual. In the short list consultation modelling, all investment options alleviated the voltage stability constraint to the extent that it never bound, so to save time they have not been modelled in this analysis.

A sum of circuit flows constraint has been included to address thermal constraints in the event of contingencies involving three-terminal circuits. These constraints bind infrequently for the counterfactual[8] and the investment options.

To illustrate, Figure 3 and Figure 4 show the flow duration curves across the WUNI boundary for the Growth scenario for the counterfactual and the investment options. The flow duration curves shown are for each hour in 2045 for all hydro scenarios. The counterfactual is more constrained than the investment options, leading to the dispatch benefits for each investment option.

[8] All counterfactual results are labeled as Option 0 in the charts in this report.

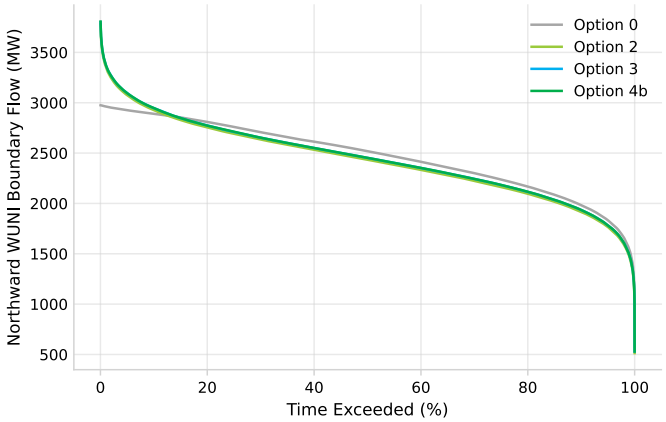


Figure 3: Flow duration curves (2045) for flow across the WUNI boundary – Growth scenario

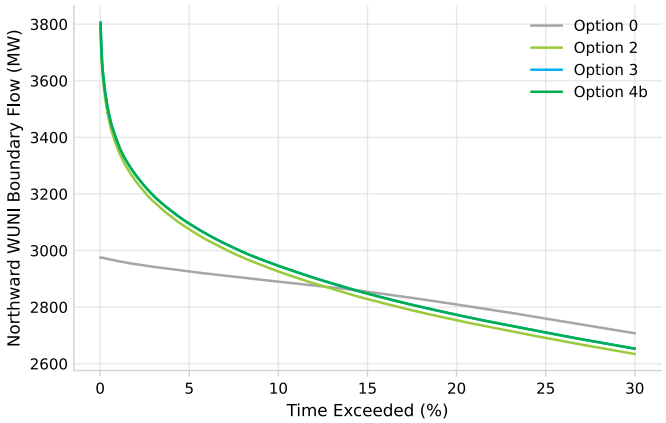


Figure 4: Flow duration curves (2045, top 30% of sum of flows) for flow across the WUNI boundary – Growth scenario

6.2.3 AC Loss Benefits

We analysed the AC losses for relevant circuits within the WUNI region. For the Growth scenario, Figure 5 shows the counterfactual AC loss costs for each circuit sorted from highest to lowest. The largest losses occur in the OHW–WKM-1 and HAM–WKM-1 circuits, followed by the two HTT–OTA circuits.

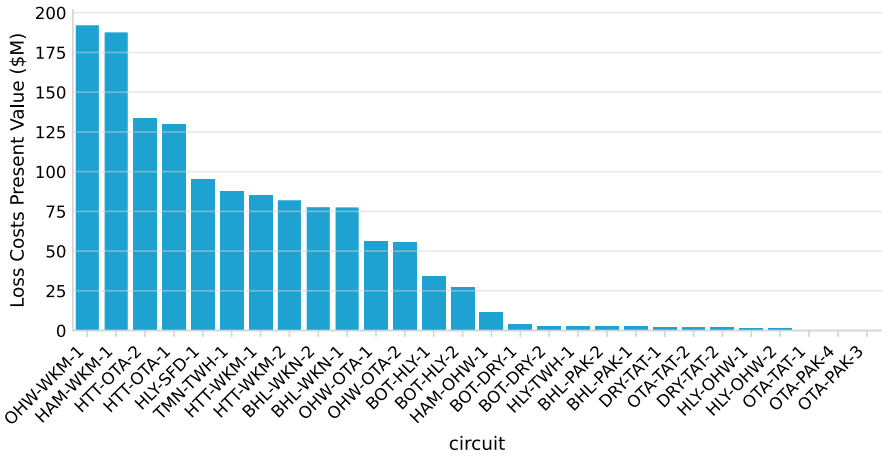


Figure 5: Counterfactual AC loss costs (present value, 5% discount rate) for each circuit considered in the Growth scenario

The AC loss benefits are illustrated in Figure 6 after comparing the AC loss costs for each circuit in each investment option against the counterfactual. All options provide large benefits by diverting flow from the lossy OHW–WKM–1 and HAM–WKM–1 circuits. Options 3 and 4 also have large benefits from the decommissioning of the lossy HTT–OTA circuits, the lower resistance of the duplexed HTT–WKM circuits and the duplexed HTT–OHW and OHW–OTA circuits. In total, the positive (blue) benefits due to lower resistance or decreased flow outweigh the negative (green) circuits that have increased flow, i.e. there is an overall net positive benefit for AC losses for all investment options.

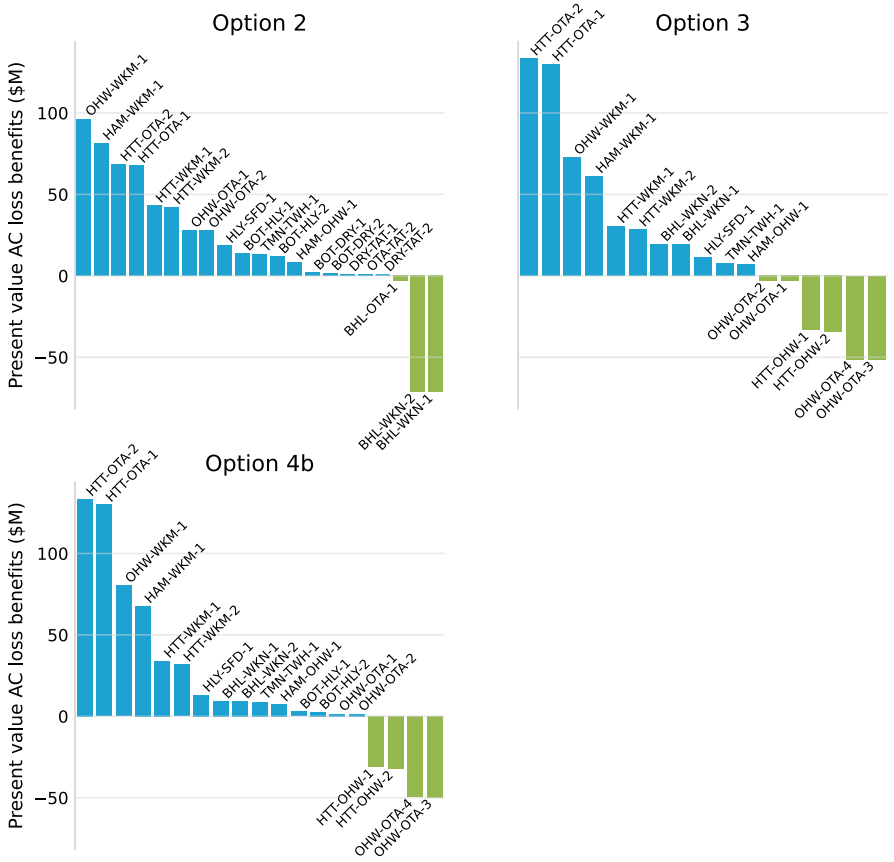


Figure 6: AC loss benefits (present value, 5% discount rate) for each circuit considered in the Growth scenario

6.2.4 Thermal operating benefits

After AC loss benefits, the next largest benefit is due to the reduction of thermal operating costs, which are significant in the Environmental and Growth scenarios. Figure 7 shows that these are mainly reductions in gas contract costs[9]. The Growth scenario also has significant reductions in emissions costs[10].

[9] Gas contract costs also include biodiesel for the Environmental scenario.

[10] There are no emissions reductions associated with gas contracts in the Environmental scenario because biogas and biodiesel are modelled as carbon neutral.

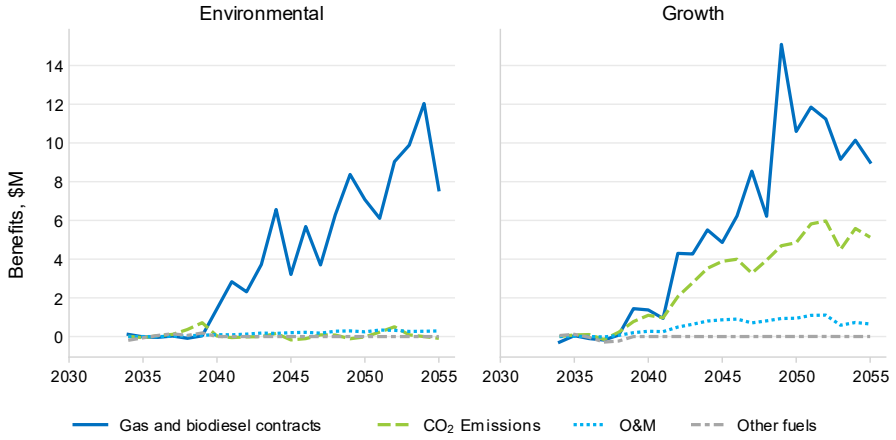


Figure 7: Breakdown of thermal operating benefits for Option 4b (present value, 5% discount rate)

Figure 8 shows the contribution of each fuel to the reduction in gas contract costs for the Environmental and Growth scenarios. These correspond mainly to fuel use reductions at two future thermal peakers connected at Huntly: one OCGT and one reciprocating engine. Although Option 4b reduces contract costs overall, it also causes small cost increases for thermal peakers outside the WUNI region by enabling them to supply more electricity into the WUNI region.

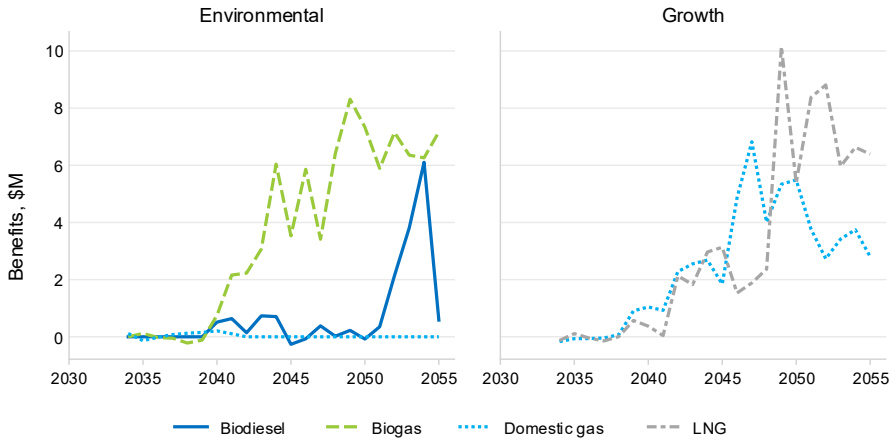


Figure 8: Gas and biodiesel contract benefits for Option 4b (present value, 5% discount rate)

6.2.5 Deficit benefits

To illustrate, Figure 9 and Figure 10 show the deficit for the Growth scenario in the WUNI region for all investment options. The deficit is averaged over all hydro scenarios.

On average, the investment options reduce deficit costs beginning around mid-2030s. For all our investment options there will always be some residual deficit across the country associated with either dry years or generation capacity shortages. For these types of events SDDP spreads deficit across the Island in proportion to demand.

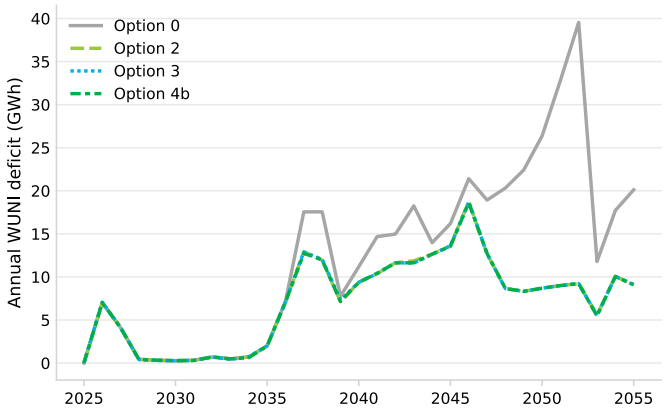


Figure 9: Deficit in the WUNI region for the Growth scenario, averaged over all hydro scenarios

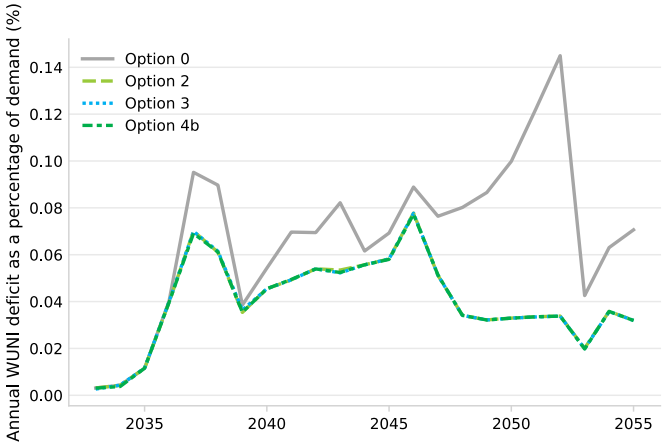


Figure 10: Deficit in the WUNI region for the Growth scenario as a percentage of total WUNI load, averaged over all hydro scenarios

Appendix A – Transmission network assumptions

A1 Short-listed options following short list consultation feedback

Generation assumptions were revised following the short-list consultation feedback. The key changes include updated Huntly thermal generation assumptions, additional wind generation at Te Uku and Kaiwaikawe, and new BESS projects, with a 15% capacity factor assumed for all BESS installations. These changes increase generation capability by up to 193 MW and 126 Mvar before 2035, and by 104 MW and 52 Mvar thereafter. We note that some of these generation assumptions (e.g., 15% capacity factor for BESS) relate only to the Power System Analysis outlined in Section 2 and not what was assumed in SDDP modelling. These assumptions reflect the requirements and level of representation appropriate to PowerFactory modelling.

Option 1, which included series capacitors on the BHL–WKM circuits together with a tee connection at Ōhinewai, was no longer considered due to technical issues.

- **Option 0:** Do nothing (Ōtāhuhu STATCOM in service)
- **Option 2:** 26.15 Ohm series compensation, BHL-OTA cable
  - +/- 150 Mvar STATCOM in North Auckland
  - 2x 26.15 Ohm series capacitors at Hangawera Road / Install additional 2x9.22 Ohm series capacitors at a site north of Ōhinewai
  - 220 kV Brownhill bus
  - 220 kV Brownhill–Ōtāhuhu cable
  - Shunt Capacitors and Dynamic Reactive Plant as required
- **Option 3:** Ōtāhuhu–Whakamaru duplexing
  - +/- 150 Mvar STATCOM in North Auckland
  - Reconductoring of Ōtāhuhu–Whakamaru A&B line south of Ōhinewai
  - Connect Ōtāhuhu–Whakamaru A&B line into Ōhinewai
  - Shunt Capacitors and Dynamic Reactive Plant as required
- **Option 4b:** Ōtāhuhu–Whakamaru duplexing, 16.93 Ohm series compensation
  - +/- 150 Mvar STATCOM in North Auckland
  - Reconductoring of Ōtāhuhu–Whakamaru A&B line south of Ōhinewai
  - 2x16.93 Ohm series capacitors at Hangawera Road
  - Shunt Capacitors and Dynamic Reactive Plant as required

Table 4: Transmission options summary

Upgrade	0	2	3	4b	Modelled Commissioning Date
Automatic over-voltage switching scheme (AOVCS)	✓	✓	✓	✓	2024
Ōtāhuhu STATCOM in service	✓	✓	✓	✓	2025
OTA-WKM VLR	✓	✓	✓	✓	2025
Hautapu GXP+VLR	✓	✓	✓	✓	2025
Hobson St second 220/110 kV transformer, Split Liverpool St – Hobson Street 110 kV	✓	✓	✓	✓	2027
Bombay 110 kV changes	✓	✓	✓	✓	2027
1x100 Mvar PAK capacitor (220 kV)		✓	✓	✓	2030
+/- 150 Mvar STATCOM at Henderson		✓	✓	✓	2031
1x100 Mvar PEN capacitor		✓	✓	✓	2032
2x75 Mvar OHW capacitor (220 kV)		✓	✓	✓	2032
220 kV Brownhill bus		✓			2033
220 kV Brownhill–Ōtāhuhu cable		✓			2033
2x26.15 Ohm series capacitors at Hangawera Road		✓			2033
Connect Ōtāhuhu–Whakamaru A&B line into Ōhinewai			✓	✓	2033
Reconductoring of Ōtāhuhu–Whakamaru A&B line south of Ōhinewai			✓	✓	2033

Note: Investments planned beyond 2033 are not included in this table.

A2 Common modelled projects

These modelled projects are applied to all transmission options.

A2.1 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.

Table 5: Penrose reactor line upgrade or new line

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

A2.2 Hautapu GXP+VLR

The OTA–WKM 1 and 2 circuits will be bussed at the new GXP, Hautapu. The new 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.

Table 6: Decommissioned Lines

Line Name	Date
OTA-WKM-1	2025
OTA-WKM-2	2025

Table 7: Line upgrade or new lines for Hautapu GXP

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

A2.3 Bombay 110 kV circuits

Currently, both BOB–HAM–1 and ARI–BOB–1 circuits are out of service. It is intended to dismantle BOB–HAM–1 and bus ARI–BOB–1 at Hamilton and dismantle the section between BOB and HAM.

Table 8: Decommissioned Lines

Line Name	Date
BOB-HAM-1	2025
ARI-BOB-1	2026

Table 9: Line upgrade or new line for Bombay

Line Name	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

Table 10: VLR on OHW-WKM-1 and HAM-WKM-1

Line Name	R (Ohm)	X (Ohm)	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Mod Date	Voltage (kV)
HAM-WKM-1	4.05	26.25	760.6	788.8	780.4	2028	220
OHW-WKM-1	5.26	34.11	760.2	772.4	765.5	2028	220

A3 Network modification

SDDP grid data was updated in March 2026. This update also included future committed projects.

We have further made modifications for each investment option as summarised in Table 4.

A3.1 Option 0 (counterfactual): existing grid

Option 0 includes only the grid modifications listed in the Common Modelled Projects section above.

A3.2 Option 2: 26.15 Ohm series compensation, BHL-OTA cable

In this option, 2×26.15 series capacitors will be added into BHL-PAK-WKN at Hangawera Road on both BHL-WKN circuits in 2033.

Also, to prevent overloading of BHL-PAK cables while increasing the compensation level, 220 kV Brownhill bus and 220 kV Brownhill-Ōtāhuhu cable shall be built in 2033. The new configuration is shown in Figure 11.

Table 11: Option 2 – Line upgrade or new lines

Line Name	R (Ohm)	X (Ohm)	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Mod Date	Voltage (kV)
BHL-WKN-1 and 2 (Series compensation)	2.74	26.14	1354.3	1490.3	1424.4	2033	220
BHL-OTA cable	0.10	1.79	768.2	808.2	768.2	2033	220
HTT-WKM 1 (series reactor)	6.35	33.51	363.5	390.2	372.3	2052	220
HTT-WKM-2 (series reactor)	6.38	33.63	363.5	390.2	372.3	2052	220

The static and dynamic reactive plants will be added to WUNI based on Table 4.

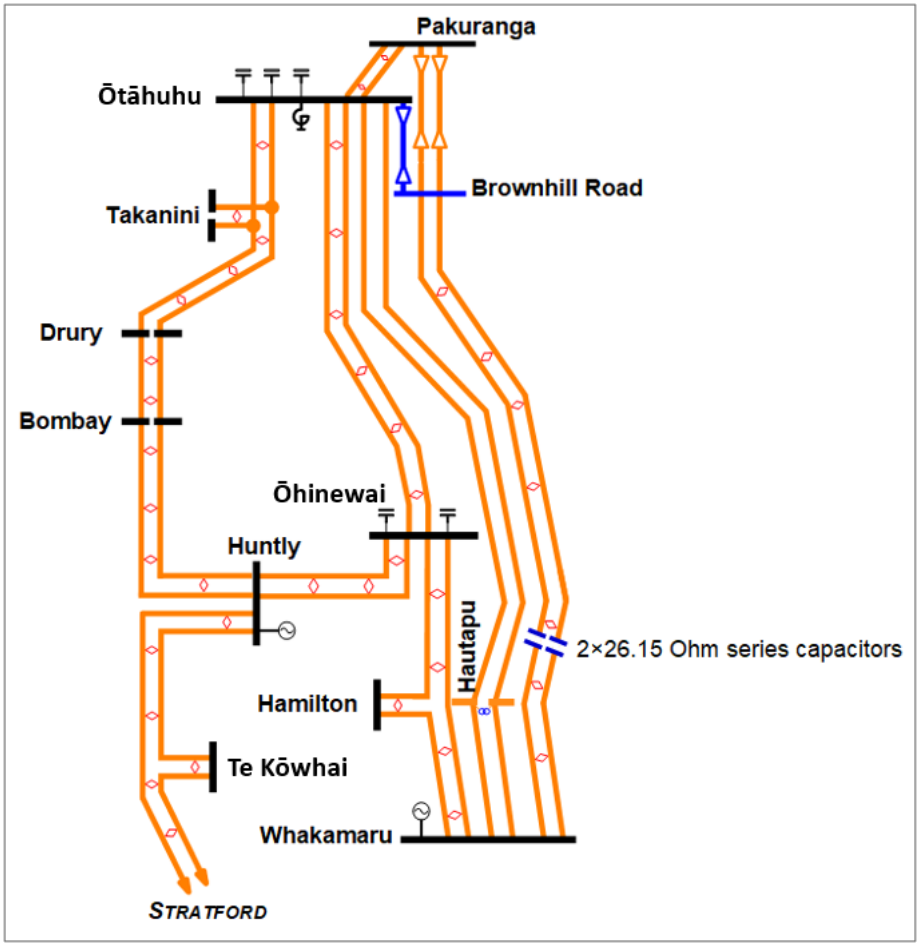


Figure 11: The grid configuration of Option 2 to 2033

A3.3 Option 3: Ōtāhuhu–Whakamaru duplexing

This option includes the following investments in 2033:

- Duplexing the Ōtāhuhu–Whakamaru A&B lines south of Ōhinewai
- Connecting the Ōtāhuhu–Whakamaru A&B lines to Ōhinewai.

The new 220 kV configuration has been shown in Figure 12.

Table 12: Option 3 – 220 kV line upgrade or new lines

Line Name	R (Ohm)	X (Ohm)	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Mod Date	Voltage (kV)
HTT-WKM-1 and 2	2.33	20.61	709.5	780.8	746.1	2033	220
HTT-OHW-1 and 2	1.49	13.22	709.5	780.8	746.1	2033	220
OHW-OTA-3	6.29	30.51	362.4	370.4	368.1	2033	220
OHW-OTA-4	6.29	30.57	362.4	370.4	368.1	2033	220
OHW-OTA-3 (series reactor)	6.29	33.51	362.4	370.4	368.1	2050	220
OHW-OTA-4 (series reactor)	6.29	33.57	362.4	370.4	368.1	2050	220

Table 13: Decommissioned Lines

Line Name	Date
HTT-OTA-1	2033
HTT-OTA-2	2033

The static and dynamic reactive plants will be added to WUNI based on Table 4.

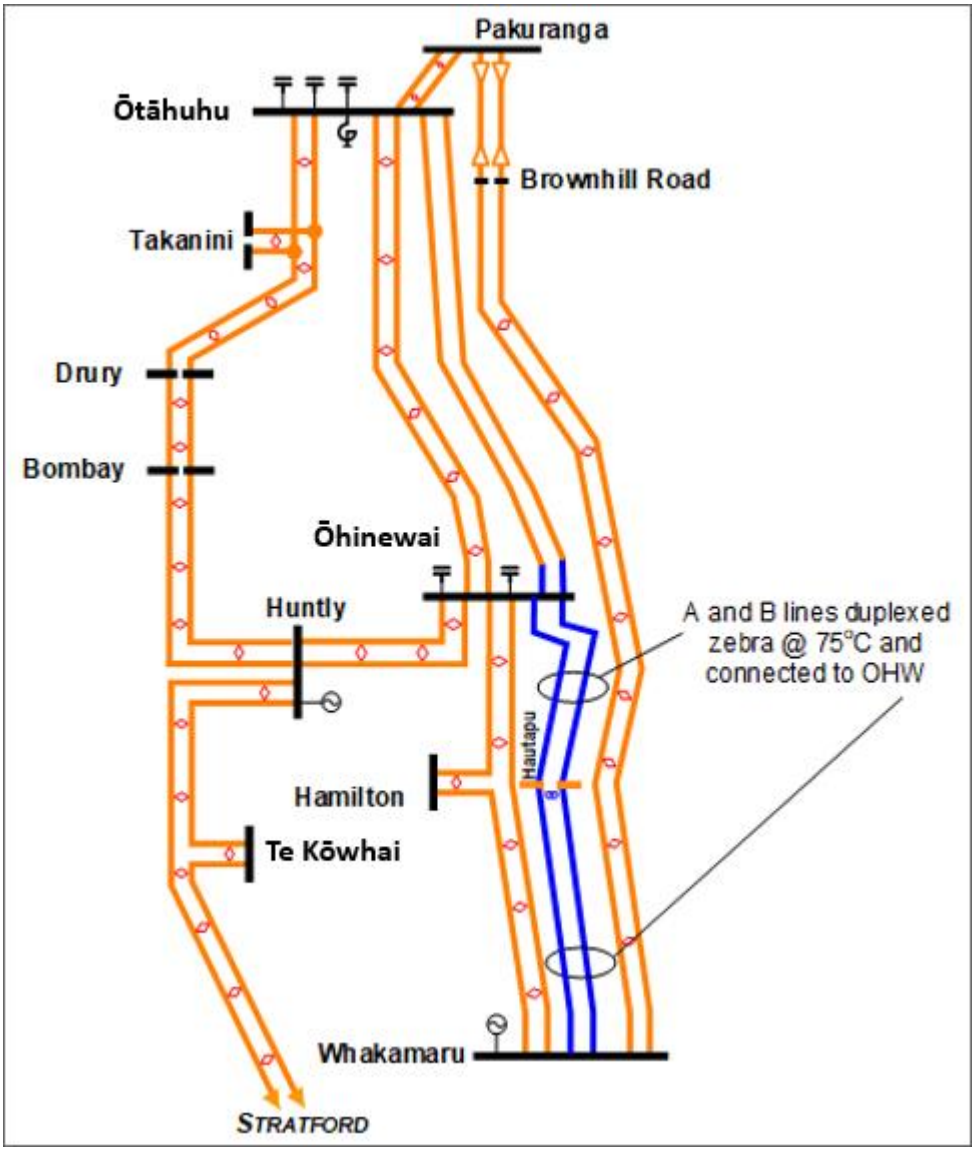


Figure 12: The grid configuration of Option 3 to 2033

A3.4 Option 4b: Ōtāhuhu–Whakamaru duplexing,16.93 Ohm series compensation

This option includes the following investments:

- Duplexing the Ōtāhuhu–Whakamaru A&B lines south of Ōhinewai in 2033
- Connecting the Ōtāhuhu–Whakamaru A&B lines to Ōhinewai in 2033
- Adding 2×16.93 series capacitors into BHL-PAK-WKN at Hangawera Road in 2049

The new 220 kV configuration has been shown in in Figure 13.

Table 14: Option 4b – 220 kV line upgrade or new lines

Line Name	R (Ohm)	X (Ohm)	Summer (MVA)	Winter (MVA)	Shoulder (MVA)	Mod Date	Voltage (kV)
HTT-WKM-1 and 2	2.33	20.61	709.5	780.8	746.1	2033	220
HTT-OHW-1 and 2	1.49	13.22	709.5	780.8	746.1	2033	220
OHW-OTA-3	6.29	30.51	362.4	370.4	368.1	2033	220
OHW-OTA-4	6.29	30.57	362.4	370.4	368.1	2033	220
BHL-WKN-1 and 2 (Series compensation)	2.74	35.36	1354.3	1490.3	1424.4	2049	220

Table 15: Decommissioned lines

Line Name	Date
HTT-OTA-1	2033
HTT-OTA-2	2033

The static and dynamic reactive plants will be added to WUNI based on Table 4.

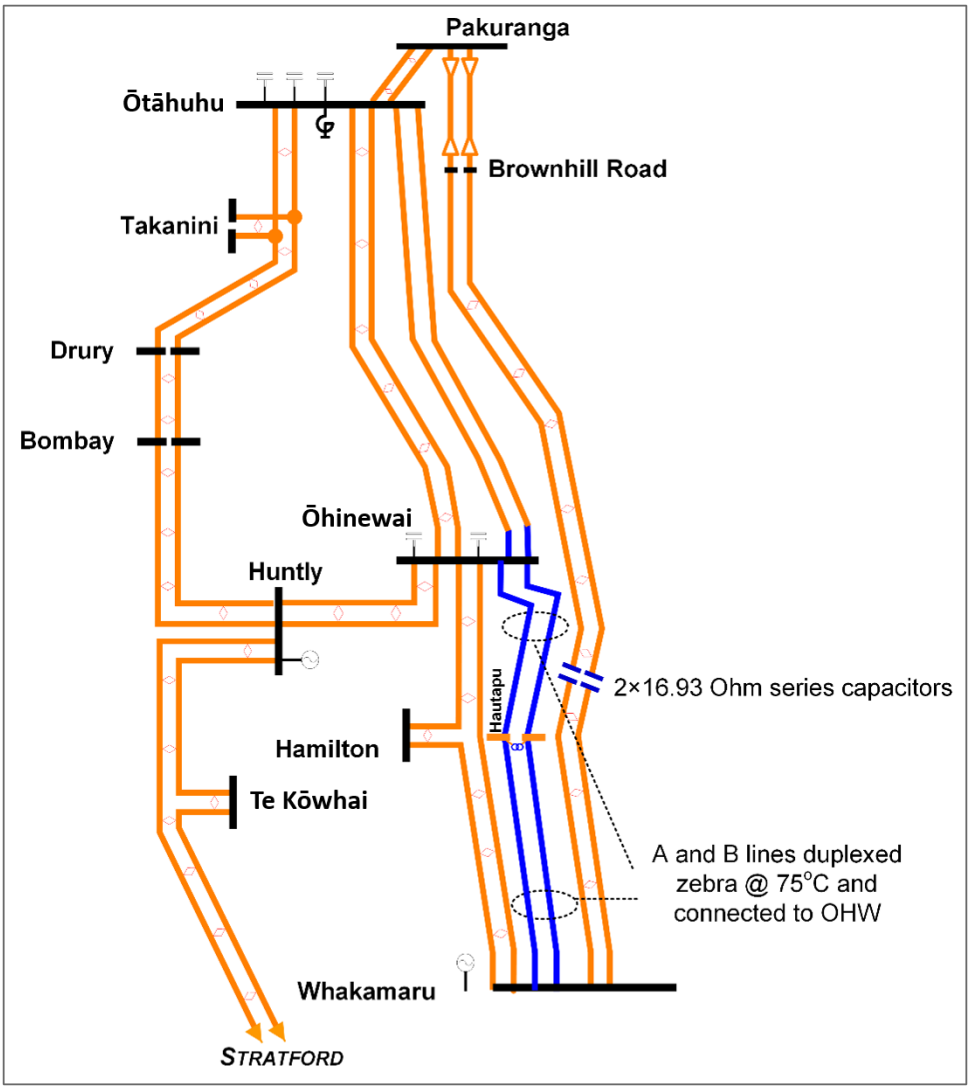


Figure 13: The grid configuration of Option 4b to 2050

A4 Transmission constraints

The economic calculations for WUNI2 project use two scenarios:

1. Existing grid (for counterfactual study) – Option 0 (Counterfactual)
2. Short-listed transmission options- Options 2, 3 and 4b

There are no constraint equations for Options 2, 3, and 4b because we assume that these options alleviate the voltage constraints modelled in option 0. This was shown to be the case in short-list modelling.

A4.1 Option 0 – Counterfactual

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

The coefficient for HLY-UN5 is (E3p), and the coefficients for any new generation at Huntly (HLY_{Gen}^{new}) could also be applied to the Rankine units. For any battery at HLY, only the discharging mode (i.e., injecting active power into the grid) were included on the LHS of the equations.

Group Constraint Equation with HLY at LHS

BHL-PAK-WKN-1 contingency equation: -1* HTT-WKM-1 + -1*HTT-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 + 0.33 * HLY_{Gen}^{new} ≤ 2975 MW
HLY-UN5 contingency equation: -1* HTT-WKM-1 + -1*HTT-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 +0.26 * HLY_{Gen}^{new} ≤ 3256 MW

Table 16: Thermal contingency for Option 0

Contingency	Monitor 1	Monitor 2	Monitor 3	Monitor 4	Monitor 5
BHL-WKN-1	HAM-WKM-1	OHW-WKM-1	BHL-PAK-2	TMN-TWH-1	HTT-WKM-1, HTT-OTA-1
HAM-WKM-1	OHW-WKM-1	BHL-PAK-2	HTT-WKM-1, HTT-OTA-1	TMN-TWH-1	
OHW-WKM-1	HAM-WKM-1	BHL-PAK-2	HTT-WKM-1, HTT-OTA-1	TMN-TWH-1	

A4.2 Option 2

The thermal contingencies for voltage stability limits are presented as follows:

Table 17: Thermal contingency for Option 2

Contingency	Monitor 1	Monitor 2	Monitor 3	Monitor 4	Monitor 5
BHL-WKN-1	HAM-WKM-1	OHW-WKM-1	HTT-WKM-1, HTT-OTA-1	TMN-TWH-1	
HAM-WKM-1	OHW-WKM-1	BHL-PAK-2	HTT-WKM-1, HTT-OTA-1	BHL-OTA-1	TMN-TWH-1
OHW-WKM-1	HAM-WKM-1	BHL-PAK-2	HTT-WKM-1, HTT-OTA-1	BHL-OTA-1	TMN-TWH-1
BHL-PAK-1	BHL-PAK-2	BHL-OTA-1	HTT-WKM-1, HTT-OTA-1		
BHL-OTA-1	BHL-PAK-2	HTT-WKM-1, HTT-OTA-1			

A4.3 Option 3

The thermal contingencies for voltage stability limits are presented as follows:

Table 18: Thermal contingency for Option 3 - (2030 and 2033)

Contingency	Monitor 1	Monitor 2	Monitor 3	Monitor 4	Monitor 5
BHL-WKN-1	OHW-OTA-3	HAM-WKM-1	BHL-PAK-2	HTT-WKM-1, HTT-OTA-1	TMN-TWH-1
HAM-WKM-1	OHW-WKM-1	BHL-PAK-2	HTT-WKM-1, HTT-OTA-1	OHW-OTA-3	TMN-TWH-1
OHW-WKM-1	HAM-WKM-1	BHL-PAK-2	HTT-WKM-1, HTT-OTA-1	OHW-OTA-3	TMN-TWH-1
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.

Contingency (**2033 onwards**): HTT-OHW-WKM-1 or 2 and Constraint: HAM-WKM-1

- Winter:

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

- Shoulder:

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

- Summer:

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

A4.4 Option 4b

The thermal contingencies for voltage stability limits are presented as follows:

Table 19: Thermal contingency for Option 4b - (2030 and 2033)

Contingency	Monitor 1	Monitor 2	Monitor 3	Monitor 4	Monitor 5
BHL-WKN-1	OHW-OTA-3	HAM-WKM-1	BHL-PAK-2	HTT-WKM-1, HTT-OTA-1	BHL-WKN-1
HAM-WKM-1	OHW-WKM-1	BHL-PAK-2	HTT-WKM-1, HTT-OTA-1	OHW-OTA-3	HAM-WKM-1
OHW-WKM-1	HAM-WKM-1	BHL-PAK-2	HTT-WKM-1, HTT-OTA-1	OHW-OTA-3	OHW-WKM-1
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.

Contingency (**2033-2048**): HTT-OHW-WKM-1 or 2 and Constraint: HAM-WKM-1

- Winter:

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

- Shoulder:

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

- Summer:

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

Contingency (**2049 onwards**): HTT-OHW-WKM-1 or 2 and Constraint: HAM-WKM-1

- Winter:

  -1* HAM-WKM-1 - 0.21*HTT-WKM-1 ≤ 756 M

- Shoulder:

  -1* HAM-WKM-1 - 0.21*HTT-WKM-1 ≤ 750 MW

- Summer:

  -1* HAM-WKM-1 - 0.21*HTT-WKM-1 ≤ 735 MW

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