TRANSPOWER

Redclyffe 220 kV Switchyard Resilience Project

Major Capex Proposal

Attachment 5 - Application of the Investment Test

June 2025

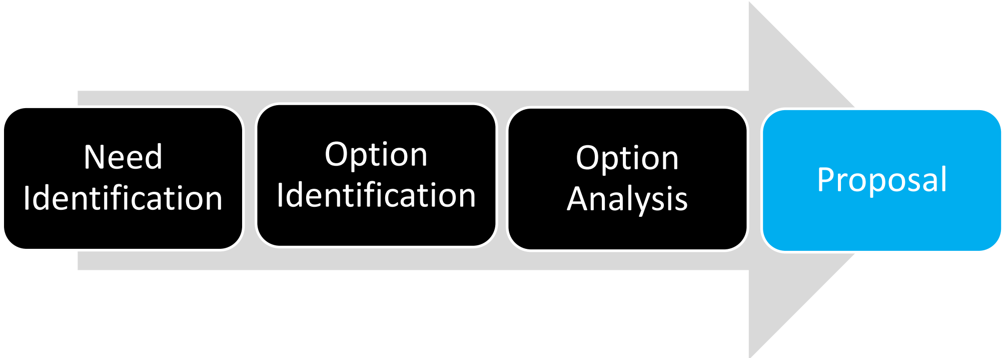
Purpose

This attachment contains an overview of our Redclyffe 220 kV Switchyard Resilience MCP options analysis and our approach to the Investment Test. It includes our application of the Investment Test and identifies our preferred option (Proposed Investment).

1 Investigation approach

The diagram below sets out the general process followed by this investigation. We are at the "Proposal" stage.

Figure 1: Transpower's standard investigation approach



The short-list options have been analysed using the Investment Test[1].

2 Electricity Demand and Generation Scenarios

The Investment Test requires that we determine the expected net electricity market benefit for each option considered. The expected net electricity market benefit for an option is the weighted average of the options net electricity market benefit under each demand and generation scenario. These scenarios are based on electricity demand and generation scenarios (EDGS) developed by the Ministry of Business, Innovation, and Employment in 2019[2].

2.1 Electricity Demand

The investment options offer different levels of resilience to flooding either by keeping the existing configuration at Redclyffe, raising the height at which critical assets are positioned at Redclyffe, or building a new GXP to modern design standards at a new location.

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1 The Investment Test is defined in Schedule D of Transpower Capital Expenditure Input Methodology.

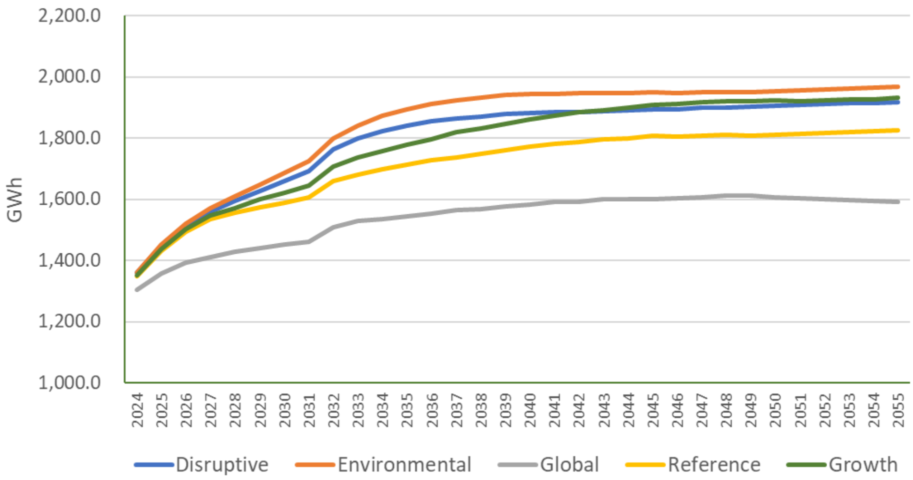
2 The scenarios used are based on EDGS 2019 but include necessary variations that were detailed in Transpower's NZGP1 major capital proposal (NZGP Latest updates | Transpower) along with updates to reflect updated lines company views of demand growth. In Capex IM language, the scenarios are demand and generation scenario variations because they are variations on EDGS 2019 (and the EDGS 2019 global scenario is not used).
Refer to Attachment 3 for more detail on the EDGS. We note that while the EDGS have been updated in 2024 these scenarios are not yet being used by Transpower in MCP assessments.

We assume that if an extreme flood overtops the flood resilience level provided by an option, then we will be faced with a similar duration event and loss of load as seen in 2023. Our estimate of the amount of unserved energy expected over the event duration will scale over time depending on the growth in future demand specified by each scenario.

2.2 Scenario weightings

Using the 2019 EDGS-based scenarios, we forecast demand on the three GXPs Redclyffe, Fernhill, and Tuai that sit on the Hawkes Bay 110 kV network, plus Whakatu GXP which is supplied at 220 kV via Redclyffe. Figure 2 shows a range of growth out to 2055, bounded by the high growth Environmental scenario and the lower growth Reference and Global scenarios.

Figure 2: Demand scenarios for Hawke's Bay 110 kV plus Whakatu



The default position is for equal weighting of scenarios. However, in our short list consultation we proposed a variance that involved dropping the Global scenario and giving equal weighting to the four remaining scenarios.

Table 1: Scenario weightings

Usage	Environmental	Global	Reference	Growth	Disruptive
Standard weighting	20%	20%	20%	20%	20%
Proposed weighting	25%	0%	25%	25%	25%

Respondents to our short-list consultation did not express any views on the scenarios we used for this analysis or their weighting.

2.3 Generation Development

The short-list options, while offering varying levels of flood resilience, are largely electrically equivalent. Consequently, when comparing the options there is no need to model market pricing impacts, nor do we need to consider the differences in the generation supply mix and the location supplying power to the region.

Some of the scenarios may include additional generation within the region but our experience from Cyclone Gabrielle was that power supply and communication systems within the Hawke's Bay 110 kV system were lost immediately following the inundation of assets at Redclyffe.

3 Investment Test parameters

This section describes the Investment Test parameters used in our analysis.

3.1 Calculation period

The default calculation period for the Investment Test is 20 years, but a different period can be used where appropriate.

For this analysis, we extended the calculation period to 2090. The reasons include:

- The longer calculation period aligns with the economic lifetime of the switchyard assets and allows more resilience benefit to be captured.
- The investment need is to increase resilience to High Impact Low Probability (**HILP**) flood events. The capital investment proposed will be made in the next few years but the benefits from reduced flood risk will only accrue over the future lifetime of the switchyard. To fully capture the benefits, we need to look over a much longer period than 20 years.
- Our modelling of rainfall, river flow and flood level and associated probabilities are informed by NIWA climate change modelling.[3] This modelling is itself informed by the work of the Intergovernmental Panel on Climate Change (IPCC), and their Representative Concentration Pathways (RCPs). The RCPs are a set of climate change scenarios that model how greenhouse gas concentrations will change in the future, and how this will impact the climate, and the temperature and rainfall impacts expected by 2081-2100. 2090 is typically taken as the midpoint of this interval and used to present expectations of temperature and rainfall change.

The modelling of annual benefits from increased resilience to floods is discussed in detail in Attachment 3 and is of a nature that allows relatively straightforward computations to be completed efficiently in a spreadsheet model. Intensive OptGen or SDDP modelling to capture future benefits has not been required.

While we have extended the calculation period to 2090, we have not included any costs for replacement or enhancement of assets that may be required beyond 2035 to allow for future load growth in the period out to 2090.

3.2 Discount rate

We have used the Capex IM default discount rate of 5% for this analysis, with a sensitivity range of 3% to 7%.

3 https://niwa.co.nz/climate-and-weather/climate-change-scenarios-new-zealand

3.3 Value of expected unserved energy

The value of expected unserved energy represents the economic value, in dollars per MWh, that a consumer places on electricity they expect to consume but do not receive because of a power interruption. We use this value to assess reliability benefits, in situations where different options deliver differing levels of reliability of supply. The default[4] value of expected unserved energy is $20,000 per MWh. This value was determined in December 2004 and accounting for inflation, equates to approximately $33,000 per MWh in 2025.

We also consider sensitivity cases of $10,000 per MWh, $20,000 per MWh and $50,000 per MWh.

4 Calculating Expected Net Electricity Market Benefits

4.1 Electricity market costs and benefits

Electricity market costs and benefits are costs and benefits incurred and received by consumers in the electricity market during the relevant calculation period that will affect net electricity market benefit.

The nature of the investment need and short-list options in this case is such that we consider most of the electricity market costs and benefits specified in the Capex IM do not vary materially between the options. For example, and unlike many other proposed major capex projects, whatever resiliency investment we make at Redclyffe will not have an impact on losses or power flows. Accordingly, for this analysis, the only electricity market cost or benefit we have accounted for in the Investment Test are the differences in resilience benefits between the options.

We note that this approach probably underestimates the expected net electricity market benefits of Options 2 and 3 because Option 2 (the Proposed Investment) and Option 3 include new assets and a digital substation[5] installation, and they may have lower maintenance costs than the existing configuration at Redclyffe.

4.2 Project costs

Project costs are costs reasonably incurred, prior to or during the calculation period, in undertaking a major capex project. In this analysis we have included the following:

- Capex expected for Option 2 Rebuild and Option 3 Relocate.
- Option 1 Repair - costs for the future replacement of ageing assets including the replacement of the temporary control room at Redclyffe.

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4 The Capex IM states that the default value of expected unserved energy is equivalent to the value defined in the Electricity Industry Participation Code (Part 12, Schedule 12.2, clause 4).

5 A Digital Substation integrates essential components like circuit breakers, protection relays, current transformers (**CT**s), and voltage transformers (**VT**s) using optical fibre instead of numerous copper cables. This simplifies the physical setup of the substation, making it more efficient and easier to manage. Digital Substations offer improved reliability, enhanced data communication, and reduced maintenance costs, making them a preferred choice for upgrading electrical systems.

The work recovering the Redclyffe 220 kV Switchyard's ability to provide its pre-Cyclone level of service has already been completed, and these costs are now sunk. We have not included these costs in the Investment Test. However, Option 1 involves the future replacement of ageing assets and the temporary control room at Redclyffe. These asset replacements are known and would occur within the next decade. We have included them in Option 1's project costs for the Investment Test. These include future capital costs required for asset replacements with an estimated $16.7m of capital works required to maintain and replace ageing assets through to 2033. This work includes Bus Zone and Bus Coupler Protection Replacement, Line Protection & ODJB (Outdoor Junction Box) Replacement and a permanent control room replacement. The temporary 220 kV control room constructed post Cyclone Gabrielle is not fit for the longer-term use and a permanent replacement is required to meet earthquake standard and to allow for modern operating safety standards.

The cost estimate identified for Option 2 (the Proposed Investment) is now of Class 3[6] quality following significant design work. The range of cost uncertainty is tested in the sensitivity analysis with a view to determining whether the proposed option is robust to variations in capital cost.

The cost estimate for Option 1 can be considered of Class 4 accuracy while Option 3 has been made at a lesser level of accuracy (Class 5) and includes estimates of the significant distribution network costs that would need to be met to reconnect the existing Unison Network at a new location. While these costs will fall to Unison including costs and benefits for both Transpower's and Unison's plans ensures that the option with the greatest net benefit for end consumers is identified.

Opex costs have not been quantified with the difference in Opex between options likely to be small. This approach probably underestimates the expected net electricity market benefits of Options 2 and 3 as both include newer assets and a digital substation, which may have lower maintenance costs than the existing configuration at Redclyffe.

4.3 Expected net electricity market benefit

We have calculated the net electricity market benefits for Options 2 and 3 relatives to Option 1 for each electricity demand and generation scenario used in this analysis. The net electricity market benefit for each option in each scenario is the difference between the option's net benefit in that scenario and the option's total project cost.

The expected net electricity market benefit for an option is the weighted average of the net benefit of the option under each scenario. We have weighted the scenarios equally, where the weightings are those presented in Table 1.

4.4 Passing the Investment Test

The Investment Test is satisfied in respect of a proposed investment if the proposed investment is an investment option that:

- is sufficiently robust under sensitivity analysis;
- has a positive expected net electricity market benefit; and

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6 Ref AACE standard www.aacei.org

- has the highest expected net electricity market benefit, where only quantified electricity market benefit or cost elements are taken into account.

4.5 Our application of the Investment Test

The Investment Test is an economic cost-benefit test using the real value of costs and benefits. Future spending and costs are discounted at a rate of 5% per annum reflecting the time-value of money, as discussed in section 3.2 above.

Our analysis includes the project cost associated with each of our short-list options.

In Option 3, some capital cost will fall to Unison as it will be necessary for Unison to construct a suitable connection to the new substation location. Although these costs are not project costs as defined in the Capex IM,[7] we have included them as part of the Option 3 project cost for convenience and because doing so does not affect the outcome of the Investment Test - costs and benefits for both Transpower and Unison are captured to ensure that the option with the highest positive expected net electricity market benefit is identified.

Table 2 shows the present value of the project cost for each short-list option (including Unison's capital costs for Option 3).

Table 2: Project costs for short list options

	Option 1 Repair	Option 2 Rebuild	Option 3 Relocate
Undiscounted project cost ($m, real 2025)[8]	16.7	43.1	280.0
Discounted project cost ($m, 2025 present value)	15.4	39.9	216.2

As discussed above, the only electricity market cost or benefit we have accounted for in the Investment Test are the differences in resilience benefits between the short-list options. We do not consider the other electricity market costs or benefits specified in the Capex IM vary materially between the options.

Resilience benefits relate to being able to supply electricity following a HILP event that would otherwise result in an interruption.

Option 1 retains the current flood resilience to a 100-year ARI event (in 2090, being the end of the calculation period for this analysis) while Options 2 and 3 both provide flood resilience at the modern design standard of a 450-year ARI event (in 2090).

Option 3 has higher expected flood costs and lower resilience benefit as it is not expected to be commissioned until 2036, so the current flood risk would remain for the 11 years 2025-2035. Option 2 is expected to be commissioned by December 2027.

See Attachment 3 for more detail on the flood and resilience modelling.

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7 Under the Capex IM project costs are limited to costs incurred by Transpower.

8 Undiscounted capital costs in both Transpower's transmission grid and (for Option 3) Unison's distribution network.

Table 3: Flood costs, 2025 present values at 5% discount rate ($m)

	Option 1 Repair Do minimal	Option 2 Rebuild Redclyffe 220 kV Switchyard	Option 3 Relocate New GXP
Future flood costs - unserved energy (2025 $m)	50.3	14.8	24.2
Future flood costs - repairs (2025 $m)	1.8	0.5	0.9
Future flood costs - total	52.1	15.4	25.1

Table 4 presents the quantified expected net electricity market benefits for the short-list options relative to Option 1 (the base case):

Table 4: Quantified expected net electricity market benefits, present values at 5% discount rate (2025 $m)

	Option 1 Repair Do minimal	Option 2 Rebuild Redclyffe 220 kV Switchyard	Option 3 Relocate New GXP
Project costs	15.4	39.9	216.2
Future flood costs - unserved energy	50.3	14.8	24.2
Future flood costs - repairs	1.8	0.5	0.9
Future flood costs - total	52.1	15.4	25.1
Total quantified costs	67.5	55.2	241.3
Relative expected net electricity market benefit	0.0	12.2	-173.8

Option 2 has the highest expected net electricity market benefit, and its expected net electricity market benefit is positive.

5 Sensitivity Analysis

The Investment Test sensitivity analysis considers the effect of varying key inputs.
We considered the following parameters to be relevant (with the standard assumptions shown):

- Discount rate: 5%
- Value of unserved energy: $33,000 /MWh

- Outage duration: based on Cyclone Gabrielle unserved energy of 10,000 MWh
- Project costs: refer Table 4 above

For this analysis we have considered the following sensitivity cases to capture uncertainty in relevant inputs:

Table 5: Sensitivity cases considered

Parameter sensitised	Comment
Forecast demand	Demand varies by scenario and net benefit is reported for each of the four scenarios.
Size, timing, location, costs, as relevant to existing assets, committed projects, modelled projects and the investment options	New assets in the investment options do not vary by time, size, cost or location within each option or by scenario. No sensitivity cases.
Capital cost of the investment options and modelled projects.	Sensitivities are considered where capital cost is increased by 30% and decreased by 30%.
Timing of decommissioning, removing or de-rating decommissioned assets;	Not relevant. No sensitivity cases.
Value of expected unserved energy (VoLL[22])	Sensitivities of $10,000 per MWh, $20,000 per MWh and $50,000 per MWh are reported.
Scenario weightings	An equally weighted scenario net benefit is reported along with the net benefit for each scenario individually (100% weighting). Other combinations not relevant.
Discount rate	Sensitivities of 3% and 7% are reported.
Range of hydrological inflow sequences	Not relevant. No sensitivity cases.
Competition effects	Not relevant.
Duration of the interruption from flood event	Sensitivity of +25% and -25% are reported.

The results of the sensitivity analysis are recorded in Table 6. Note: green denotes the option with highest expected net market benefit for a given sensitivity.

Table 6: Quantified expected net electricity market benefits, sensitivity analysis ($m, 2025 present value)

Sensitivity	Option 1	Option 2	Option 3
Standard assumptions - Disruptive	0	11.1	-174.7
Standard assumptions - Environmental	0	13.2	-173.1
Standard assumptions - Growth	0	12.4	-173.5
Standard assumptions - Reference	0	10.9	-174.8
Standard assumptions – Equally weighted	0	12.2	-173.8
Low discount rate (3%)	0	36.0	-172.7
High discount rate (7%)	0	0.8	-165.8
Lower VoLL ($10,000)	0	-12.5	-192.0
Low VoLL ($20,000)	0	-1.8	-184.1
High VoLL ($50,000)	0	30.5	-160.3
High capital cost (+30%)	0	4.9	-234.1
Low capital cost (-30%)	0	19.6	-113.5
Longer interruption (+25%)	0	21.1	-167.3
Shorter interruption (-25%)	0	3.4	-180.3

The sensitivity analysis shows that Option 2 provides the greatest expected net electricity market benefit across the four demand scenarios under the standard assumptions for VoLL, capital cost, discount rate and interruption duration.

Option 2 also provides the greatest expected net electricity market benefit across nearly all sensitivity cases, only falling behind Option 1 in the presence of lower VoLLs.

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