TRANSPOWER

Lower South Island: Major Capex Proposal Longlist Consultation

Attachment 3: Investment Test parameters

November 2026



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1 Overview

This attachment outlines the Investment Test parameters we propose to use for this MCP investigation. The Investment Test is the economic test specified in the Capital Expenditure Input Methodology (Capex IM), which Transpower uses to assess the costs and benefits of transmission investment options.

For the Lower South Island MCP, we will apply the Investment Test to a refined shortlist of development plans to help identify the circumstances in which different upgrades could deliver the greatest expected net electricity market benefit.

The Capex IM requires Transpower to specify the following parameters for the Investment Test:

- any non-standard values or amounts for the calculation period or value of expected unserved energy that it may use for the purpose of the Investment Test
- any non-standard discount rate that it may use for the purpose of the Investment Test.

This attachment describes the default values for each of these, specifies where we have chosen alternative values for the parameter, and provides our rationale for using an alternative value.

Any investment approved by the Commerce Commission through this MCP process, and made by Transpower, will be a benefit-based investment (BBI) under the Transmission Pricing Methodology (TPM) and its costs will be recovered as benefit-based charges (BBCs). The TPM requires Transpower to consult on and publish a BBC Assumptions Book (Assumptions Book) that contains the assumptions and methodologies we intend to apply in allocating BBCs. The TPM also requires our application of the TPM to be as consistent as reasonably practicable with our application of the Investment Test. Below we note some of these assumptions as they relate to Investment Test parameters.

2 Investment Test parameters

2.1 Calculation period

The Capex IM states that the default calculation period for costs and benefits is 20 years past the commissioning date of the last investment but allows for a different period to be used if we consider it appropriate.

Some transmission assets have lives longer than 20 years, so relative benefits will continue to accrue for some options after 20 years. For the Lower South Island investigation, the timing of generation/load connections and the potential for a coordinated regional upgrade mean that some benefits may be realised over a longer horizon as generation is progressively enabled and connected.

We propose using a calculation period to 2060 for the Lower South Island analysis, to better capture the costs and benefits over the useful life of the assets. Although this is not the full economic life for some options, we consider this an appropriate trade-off between assessing benefits over the economic life of an option and the uncertainty regarding far-off benefits. The effect of discounting future benefits to present values does diminish this effect, but nevertheless it can be significant.

Q18. Do you consider the proposed calculation period to 2060 appropriate for this investigation? If not, what calculation period (or end year) would you suggest and why?

2.2 Value of expected unserved energy

The value of expected unserved energy represents the value to consumers of electricity supply lost as a result of an unplanned outage. It is typically used to assess reliability benefits where investment options provide different levels of reliability.

For the Lower South Island MCP, we do not propose to assess reliability benefits, as the primary benefits of investment are expected to arise from increased transmission capacity rather than the avoidance of unplanned outages. We therefore do not propose to apply a value of expected unserved energy in our benefit analysis.

Q19. Do you agree with our proposal to not assess reliability benefits or apply a value of expected unserved energy?

2.3 Deficit costs

While we do not intend to assess reliability benefits related to unplanned network outages, our market modelling may identify periods where demand cannot be fully supplied because there is insufficient generation available, and/or insufficient transmission capacity to deliver that generation to load. This can occur even when there have been no contingencies (for example, during a dry year). We represent the cost of this unserved demand using a deficit cost.

Deficit costs are particularly relevant when modelling the counterfactual. Without additional transmission investment, constraints on the existing network may prevent sufficient generation from reaching load in some locations, resulting in demand response or other load curtailment being required to balance supply and demand.

For this investigation, we intend to use the deficit values set out in the Assumptions Book v3.0, shown in Table 1 below. These deficit costs are intended to represent a range of responses to supply shortages as might occur in the actual operation of the electricity system, including demand response (short and long term) and forced curtailment of load (as would occur in a grid emergency).

Table 1: Deficit cost tranches

Deficit (as % of Island Hourly Demand)		
Constraint, Growth, Reference and Environmental Market Scenarios	Innovation Market Scenarios	Cost (2025$/MWh)
First 2.25% of demand	First 2.75% of demand	700
Between 2.25% and 4.5% of demand	Between 2.75% and 5.5% of demand	950
Between 4.5% and 9.5% of demand	Between 5.5% and 10.5% of demand	4,000
Greater than 9.5% of demand	Greater than 10.5% of demand	21,000

We are aware that some consumers may have different costs associated with non-supply and demand response that may vary based on the extent and duration of non-supply. We would welcome information regarding these values that we could incorporate into our modelling.

Q20. Do you agree with our proposed use of the deficit cost tranches from Assumptions Book v3.0? If not, what changes would you suggest?

Q21. Are you able to provide information on your cost of non-supply or demand response, including how these may vary with the extent and duration of non-supply?

2.4 Discount rate

The Capex IM specifies a default real pre-tax discount rate of 5%, which we propose to use as the base discount rate for this MCP. Sensitivities of 3% and 7% will also be tested.

Q22. Do you consider a discount rate of 5% (with sensitivities of 3% and 7%) appropriate for this investigation?

3 Calculating the expected net benefit

3.1 Counterfactual

The Investment Test requires us to determine a counterfactual option from which we can calculate cost and benefit differences to determine an expected net electricity market benefit for an investment option. The counterfactual is the expected future grid state that would result should no part of the proposed investment be completed (i.e., no investment is commissioned).

For an analysis of potential enhancement investments, we typically choose a counterfactual that assumes no new investment is made in the grid, other than enhancements that have already been approved or are planned. For this MCP, we will assume that Stage 1 of the HVDC Link Upgrade Programme proceeds, including the replacement of the existing HVDC submarine cables with four new cables.[1] The factual is the expected future state of the grid that will result from the completion of the BBI.

We propose that the counterfactual used in the Investment Test for this investigation will be consistent with the principles of developing the counterfactual as specified in the Assumptions Book and TPM. Given that this is an enhancement investment, the counterfactual will assume no transmission investment, beyond what is already approved or planned, to resolve the identified need. In that case, we expect electricity consumers to have higher levels of supply shortfall and/or greater levels of generation investment.

Q23. Do you agree with our intention to use a counterfactual that proposes no transmission investment to resolve the identified need(s)?

3.2 Electricity market costs and benefits

Electricity market costs and benefits are those received or incurred by consumers of the electricity market during the calculation period, and which will affect net electricity market benefits. These may include:

- fuel costs, e.g., the cost of generating electricity
- cost of involuntary demand curtailment, e.g., the cost of lost load
- cost of demand-side management
- capital costs of modelled projects e.g., future assets that are likely to exist whose nature and timing is affected by an investment option, for instance new generation

[1] The Commerce Commission approved the HVDC Stage 1 major capex proposal in June 2026.

- relevant operation and maintenance costs, e.g., costs of existing assets, options and modelled projects
- cost of ancillary services
- cost of losses, including transmission and local losses
- consequential operating expenditure
- third-party contributions to the cost of a project
- subsidies or other benefits provided under or arising pursuant to all electricity-related legislation and electricity-related administrative determinations
- competition effects.

We will consider costs and benefits that are relevant and material to our assessment. We may also consider relevant unquantified benefits and other net economic benefits. Our proposed treatment of these benefits will be set out in the short list consultation.

3.3 Project costs

Project costs are costs reasonably incurred by Transpower prior to or during the calculation period, in undertaking a major capex project. These include, but are not necessarily limited to:

- capital expenditure, including capital expenditure for land purchased for an option
- costs payable to a third party for testing
- costs payable for commissioning of assets
- operating, maintenance, and dismantling costs
- compliance costs relating to applicable legislation and administrative requirements.

3.4 Expected net electricity market benefit

We will determine the net electricity market benefit for each short-listed option, for each demand and generation scenario, being the aggregated quantum of each electricity market benefit or cost element less its aggregated quantum of each project cost. The expected net electricity market benefit is the weighted average of the net electricity market benefit under each demand and generation scenario, where the weighting is that determined for each demand and generation scenario.

Q23. Are there any other market costs or benefits which should be reflected in our Investment Test analysis?

Q24. Are there any unquantified benefits that should be considered in this investigation?

4 Sensitivity analysis

Sensitivity analysis means consideration, except where not reasonably practicable nor reasonably necessary, of the effect on quantum of variations in the following parameters:

- forecast demand
- size, timing, location, fuel costs and operating and maintenance costs, relevant to existing assets, committed projects, modelled projects and the investment option in question
- capital cost of the investment option in question (including variations up to the proposed major capex allowance) and modelled projects
- timing of decommissioning, removing or de-rating decommissioned assets
- the value of expected unserved energy
- discount rate
- range of hydrological inflow sequences
- relevant demand and generation scenario probability weightings
- any other variables that Transpower considers to be relatively uncertain.



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