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COMMERCE COMMISSION NEW ZEALAND
Te Komihana Tauhokohoko

# Transpower's HVDC Stage 1 major capex project proposal

## Draft decision – Attachments A to D

1 April 2026

# Associated documents

| Publication date | Reference | Title |
|---|---|---|
| **31 January 2012** | [2012] NZCC 2 | Transpower Capital Expenditure Input Methodology Determination (‘principal determination’) |
| **13 December 2023** | [2023] NZCC 39 | Transpower Capital Expenditure Input Methodology (IM Review 2023) Amendment Determination 2023 |
| **29 August 2024** | ISBN 978-1-991287-75-5 | Transpower’s individual price-quality path for the regulatory control period commencing 1 April 2025 |
| **11 December 2024** | [2024] NZCC 40 | Transpower Capital Expenditure Input Methodology (treatment of insurance entitlements) Amendment Determination 2024 |
| **5 February 2026** | N/A | [Draft] Transpower Capital Expenditure Input Methodology (Major Capex Incentive Formula) Amendment Determination 2026 |

# Contents

# Attachment A Our decision-making framework

## Purpose of this attachment

A1 This chapter provides an overview of the decision-making framework we apply in reaching our decisions on Transpower's High Voltage Direct Current (**HVDC**) Stage 1 Major Capex Project (**MCP**).

## The Capex IM

A2 Regulation under Part 4 of the Act (**Part 4**) seeks to promote the long-term benefit of consumers of regulated services.[1] These regulated services include electricity transmission services provided by Transpower.

A3 The Input Methodologies (IMs) under Part 4 are the upfront rules, processes, and requirements of Part 4 regulation.[2] Their purpose is to promote certainty for suppliers and consumers in relation to the rules, requirements and processes applying to regulated services under Part 4.[3] The IMs apply to electricity transmission services provided by Transpower.

A4 One of the IMs that applies to Transpower is the Capex IM.[4] The two major functions of the Capex IM are to provide for the scrutiny of Transpower's proposed and actual investments, and to incentivise Transpower to deliver those investments efficiently.

## Major capex projects

A5 Under clause 3.3.2 of the Capex IM, Transpower may only recover its costs relating to a major capex project if we have first approved it.

A6 Transpower submits an MCP proposal to us.[5] If we do not reject the MCP proposal,[6] we must approve, decline, or approve only some major capex project outputs of, the project (or staging project, in the case of a staged major capex project).[7]

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1 Commerce Act, s 52A.
2 Transpower Input Methodologies Determination ('principal determination') (**Transpower IM**), as amended, as at 1 April 2025.
3 Commerce Act, s 52R.
4 Along with the Capex IM, Transpower is subject to the Transpower Input Methodologies (**IMs**) which set out IMs for: cost allocation, asset valuation, treatment of taxation, cost of capital, specification of price, the incremental rolling incentive scheme, and reconsideration of the price-quality path.
5 Capex IM, clause 3.3.3(1).
6 Capex IM, clause 3.3.4 states that we may reject an MCP if it does not comply with the requirements in clause 7.4.1, or if Transpower has not complied with the requirements specified in clause 3.3.1 of the Capex IM.
7 Capex IM, clauses 3.3.5(1)(a) and (b).

A7 If we approve an MCP, we must also determine the major capex allowance (**MCA**),[8] major capex incentive rate,[9] and any exempt major capex.[10]

A8 Before we can approve or decline an MCP, we must:

A8.1 publish the MCP;[11]

A8.2 evaluate the MCP in accordance with the evaluation criteria in the Capex IM, including any further information we have received in the evaluation process;[12] and

A8.3 consult in the following ways:[13]

A8.3.1 make and publish a draft decision or decisions on the MCP;

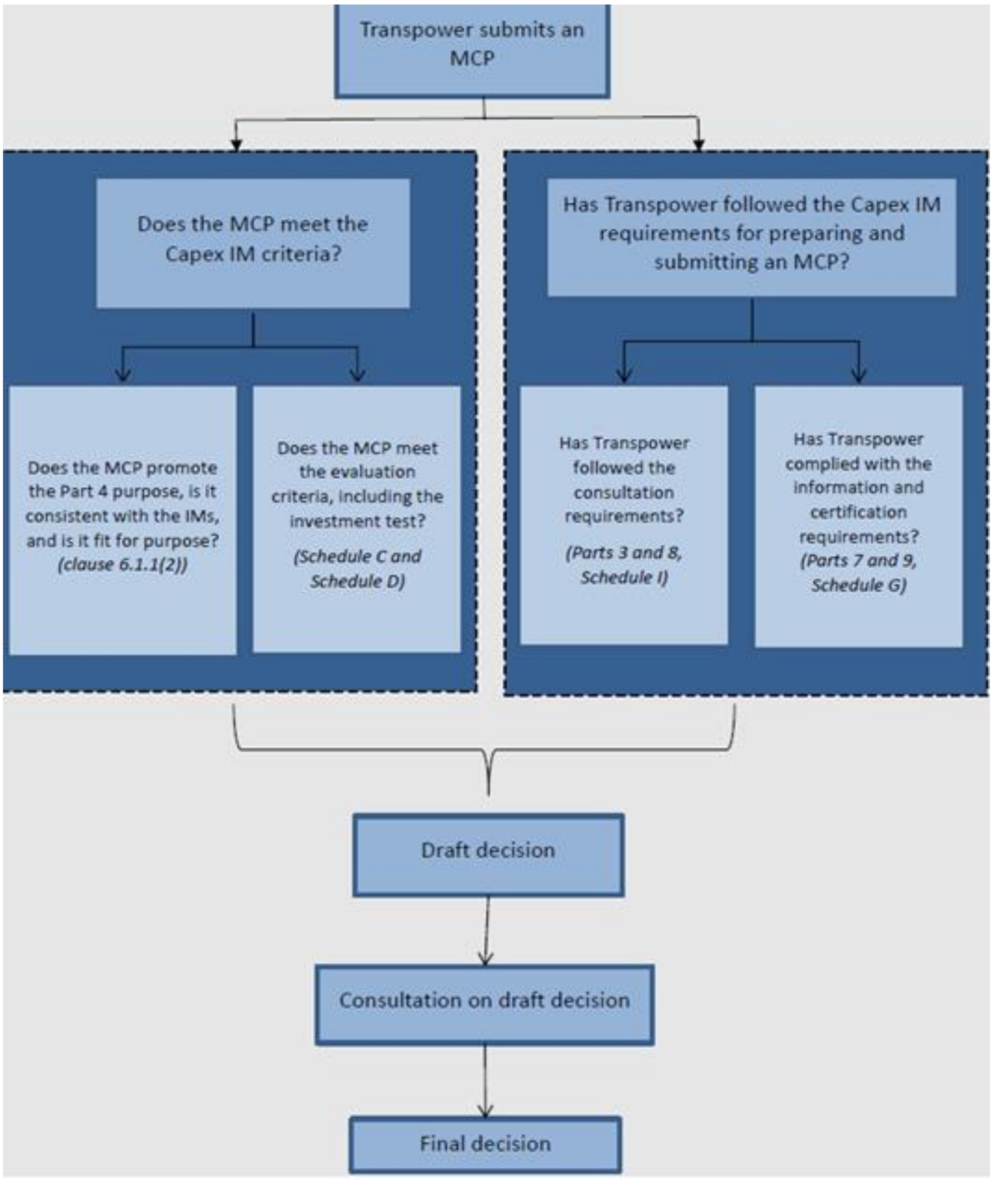
A8.3.2 seek the written views of interested persons on anything published; and

A8.3.3 seek the written views of interested persons on others' submissions.

A9 Figure A.1 below shows, at a high level, how our evaluation and decision fit into the Capex IM's regulatory approval process for major capex projects.

8 Capex IM, clause 3.3.5(7)(a).
9 Capex IM, clause 3.3.5(7)(b).
10 Capex IM, clause 3.3.5(7)(c).
11 Capex IM, clause 8.1.1(1)(a).
12 Capex IM, clause 3.3.5(5)(b)(i)-(ii).
13 Capex IM, clauses 3.3.5(5)(a) and 8.1.1(1)(a)(ii) to (iv).

**Figure A1 Capex IM regulatory approval process for major capex projects**




## Capex IM evaluation criteria

A10 This attachment sets out the evaluation criteria against which we evaluate an MCP under the Capex IM.

A11 The Capex IM requires us to evaluate an MCP against three sets of criteria:

A11.1 the general criteria for evaluating all capex proposals in Part 6;

A11.2 the specific criteria for MCPs in Schedule C; and

A11.3 the investment test in Schedule D, Division 1.

## The purpose of Part 4 of the Act

A12 The purpose of Part 4 of the Act is to promote the long-term benefit of consumers in markets where there is little or no competition, and little or no likelihood of a substantial increase in competition.[14] 'Competition' means 'workable or effective competition'.[15]

A13 To promote workable or effective competition that is in the long-term benefit of consumers, we must promote those outcomes produced in workably competitive markets which are specified in s 52A(1). Section 52A(1) of the Act specifies the following four outcomes that we must promote so that regulated suppliers, including Transpower:

A13.1 have incentives to innovate and invest;

A13.2 have incentives to improve efficiency and provide services at a quality that reflects consumer demands;

A13.3 share the benefits of efficiency gains with consumers, including through lower prices; and

A13.4 are limited in their ability to extract excessive profits.

## General criteria for evaluating MCPs

A14 The general criteria for evaluating all capex proposals under the Capex IM are:

A14.1 whether what is proposed is consistent with the Capex IM and, where relevant, the Transpower IMs;[16]

A14.2 the extent to which what is proposed will promote the purpose of Part 4 of the Act;[17] and

A14.3 whether the data, analysis, and assumptions underpinning what is proposed are fit for the purpose of the Commission exercising its powers under Part 4 of the Act, including consideration as to the accuracy and reliability of data and the reasonableness of assumptions and other matters of judgement.[18]

## Assessing whether what is proposed is consistent with the IMs

A15 The first general criterion is that an MCP must be consistent with the Capex IM and, where relevant, the Transpower IMs. We will discuss the Transpower IMs first.

A16 The Transpower IMs provide for recoverable costs associated with major capex projects and the revenue impact of such projects we have approved.[19,20]

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14 Commerce Act, s 52A(1).
15 Commerce Act, s 3(1).
16 Capex IM, clause 6.1.1(2)(a).
17 Capex IM, clause 6.1.1(2)(b).
18 Capex IM, clause 6.1.1(2)(c).
19 Transpower IM, clause 3.1.3(1)(d).
20 Transpower IM, clause 3.7.4(4).

A17 The Capex IM sets out the requirements that Transpower must follow when developing and proposing a staged major capex project, and that we must follow when evaluating an MCP for such a project.[21]

A18 When assessing whether an MCP is consistent with the Capex IM, we evaluate the proposal's compliance with:

A18.1 the process requirements;[22]

A18.2 Transpower's consultation requirements;[23]

A18.3 the information requirements;[24] and

A18.4 the certification requirements.[25]

## The process requirements

A19 The Capex IM requires Transpower to notify us of its intention to plan a major capex project or a staged major capex project.[26]

A20 Transpower must agree the following with us:

A20.1 a consultation programme;

A20.2 an approach to considering non-transmission solutions (**NTS**);

A20.3 an application date; and

A20.4 an approval timeframe.[27]

A21 Together with Transpower, we must publish the matters agreed on above and regularly review and update these matters.[28] We may (after considering Transpower's views) amend any of these matters to ensure they remain appropriate and reasonable.[29]

## Transpower's consultation requirements

A22 The requirements for Transpower's consultation programme and its approach to considering NTSs are set out in clause 8.1.3 of the Capex IM.

A23 Transpower must consult with interested parties on the following matters:[30]

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21 Capex IM, Part 3.
22 Capex IM, clause 3.3.3.
23 Capex IM, clause 8.1.3.
24 Capex IM, Schedule G.
25 Capex IM, clause 9.2.1.
26 Capex IM, clause 3.3.1(1) and (2).
27 Capex IM, clause 3.3.1(3).
28 Capex IM, clause 3.3.1(6).
29 Capex IM, clause 3.3.1(7).
30 Capex IM, clause I1(1).

A23.1 the investment need;

A23.2 each demand and generation scenario variation;

A23.3 key assumptions;

A23.4 long-list of options, including any potential NTSs (ie, the long-list consultation); and

A23.5 short-list of options including the results of the investment test (ie, the short-list consultation).

## The information requirements in a major capex proposal

A24 In the MCP Transpower must provide to us the following:

A24.1 information on the investment need;[31]

A24.2 information on the relevant demand and generation scenarios and counterfactual case;[32]

A24.3 information relating to each investment option;[33]

A24.4 information relating to proposed investment;[34]

A24.5 major capex project outputs;[35]

A24.6 information on consultation;[36]

A24.7 information on NTSs;[37] and

A24.8 any additional supporting material Transpower reasonably considers is relevant to our decision on the major capex project.[38]

A25 The Capex IM also requires that:[39]

A25.1 the number of investment options in an MCP is appropriate, given the magnitude of the estimated expenditure and the complexity of the investment need associated with the proposed investment; and

[31] Capex IM, clause G2.
[32] Capex IM, clause G3.
[33] Capex IM, clause G4.
[34] Capex IM, clause G5.
[35] Capex IM, clause G6.
[36] Capex IM, clause G7.
[37] Capex IM, clause G8.
[38] Capex IM, clause G9.
[39] Capex IM, clause 7.4.1(2) and (3).

A25.2 the specificity of information, and the rigour and comprehensiveness of the analysis for each investment option described in an MCP, must be commensurate with the estimated expenditure and complexity of that option.

## Certification requirements for MCPs

A26 Transpower's chief executive officer (**CEO**) must certify in respect of an MCP that:[40]

A26.1 the information provided by Transpower under Schedule G of the Capex IM was derived from, and accurately represents in all material respects, Transpower's operations;

A26.2 the proposed investment to which the information under Schedule G relates, was approved in accordance with the applicable requirements of Transpower's director and management approval policies; and

A26.3 the MCP complies, in all material respects, with the information requirements set out in Schedule G.

A27 Our assessment of Transpower's compliance with the general criteria is set out in Attachment B.

## Specific criteria for evaluating MCPs

A28 The specific criteria for evaluating an MCP are set out in Schedule C of the Capex IM, and are as follows:

A28.1 we must evaluate whether the proposed investment satisfies the investment test.[41]

A28.2 we must have regard to at least one of the following factors:

A28.2.1 whether the investment and investment options reflect good electricity industry practice (**GEIP**), are technically feasible, can be implemented in terms of all the application statutory planning and regulatory requirements, and can be integrated in the network and market operations;[42]

A28.2.2 whether the estimated time for construction, commissioning date, and completion date are reasonable;[43]

A28.2.3 whether key assumptions around outage planning are reasonable;[44]

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40 Capex IM, clause 9.2.1.
41 Capex IM, clause C1(1).
42 Capex IM, clause C2(a).
43 Capex IM, clause C2(b).
44 Capex IM, clause C2(c).

A28.2.4 the extent that Transpower has had regard to views of interested parties in consultations;[45] and

A28.2.5 the impact of sensitivity analysis on the electricity market benefit of the proposed investment and investment options.[46]

A28.3 we must also evaluate Transpower's proposed:

A28.3.1 MCA;[47]

A28.3.2 major capex project outputs;[48]

A28.3.3 approval expiry date;[49]

A28.3.4 major capex incentive rate;[50]

A28.3.5 exempt major capex;[51] and

A28.3.6 commissioning date assumptions.[52]

A29 The Capex IM lists evaluation techniques and approaches we may use in the specific evaluation but enables us to use any other technique of approach we consider appropriate in the circumstances.[53] We can also consider any additional information that we judge is relevant.[54]

A30 We discuss our assessment of the MCP against specific criteria in Attachment C, and our evaluation of the MCP under the investment test in Attachment D.

## Our decision on an MCP

A31 After evaluating an MCP, we must approve, decline, or approve only some major capex project outputs of, the project (or staging project, in the case of a staged major capex project).[55]

45 Capex IM, clause C2(d).
46 Capex IM, clause C2(e).
47 Capex IM, clause C1(3)(a).
48 Capex IM, clause C1(3)(d).
49 Capex IM, clause C1(3)(e).
50 Capex IM, clause C1(3)(f).
51 Capex IM, clause C1(3)(g).
52 Capex IM, clause C1(3)(h).
53 Capex IM, clause C7.
54 Capex IM, clause C7(f).
55 Capex IM, clause 3.3.5(1).
56 Capex IM, clause 6.1.1(2).

# Attachment B Our evaluation of the proposal against the general criteria

## Purpose of this attachment

B1 This attachment sets out our evaluation of:

B1.1 the HVDC Stage 1 MCP proposal against the general criteria for capex proposals set out in Part 6 of the Capex IM; and

B1.2 Transpower's consultation against the requirements of the Capex IM.

B2 All dollar values in this paper are expressed in 2025 values, unless expressed in nominal values, in which case this will be indicated with "($ nominal)".

## The general criteria in Part 6 of the Capex IM

B3 The general evaluation criteria set out in Part 6 of the Capex IM are:[56]

B3.1 whether what is proposed is consistent with the Capex IM and, where relevant, the Transpower IMs;

B3.2 the extent to which what is proposed will promote the purpose of Part 4 of the Act; and

B3.3 whether the data, analysis, and assumptions underpinning what is proposed are fit for the purpose of exercising our powers under Part 4 of the Act.

### Whether what is proposed is consistent with the Capex IM and, where relevant, the Transpower IMs

**Transpower's proposal is consistent with the Capex IM**

B4 To be consistent with the Capex IM, the proposed expenditure must be 'major capex' as defined in the Capex IM,[57] and Transpower must meet the notification, consultation, information, and certification requirements that apply.[58]

B5 We are satisfied that the proposed expenditure is major capex, and that Transpower met the Capex IM requirements on notification, consultation, information, and certification. The details of our assessment of the individual requirements follow.

56 Capex IM, clause 6.1.1(2).
57 Capex IM, clause 1.1.5(2).
58 Capex IM, clause 3.3.1, clause 7.4.1, Schedule I, Schedule G, and clause 9.2.1, respectively.

### The proposed expenditure is major capex

B6 The Capex IM defines 'major capex' as expenditure that is:[59]

- B6.1 incurred to meet the grid reliability standards (**GRS**) or provide a net electricity market benefit;
- B6.2 forecast to have an aggregate capital cost exceeding $30 million;[60] and
- B6.3 not asset replacement, asset refurbishment, business support, or information system and technology assets.

B7 The proposed expenditure for Transpower's HVDC Stage 1 MCP proposal is consistent with the Capex IM definition because:

- B7.1 it satisfies the requirements of clause D1(1) of Schedule D of the Capex IM, because it provides the highest positive expected net electricity market benefit;
- B7.2 the proposed investment provides a quantified net electricity market benefit of $66.3 million ($ 2025);[61]
- B7.3 the major capex allowance (**MCA**) is $1,138.6 million ($ nominal);[62] and
- B7.4 it is not solely incurred in relation to asset replacement, asset refurbishment, business support or information system and technology assets, rather, it is to replace and enhance existing HVDC link capacity.

### The proposed expenditure in the HVDC Stage 1 MCP meets the economic limb of the GRS

B8 For the proposed investment to meet the requirements of the Capex IM it must provide a positive expected net electricity market benefit where only quantified electricity market benefits and cost elements are taken into account.

B9 In its proposal Transpower has demonstrated that the proposed investment provides a positive net market benefit and provides the highest electricity net market benefit.

B10 The proposed expenditure has two drivers. The first driver is to replace the existing HVDC cables due to asset condition issues. The second driver is to increase HVDC capacity from 1200 MW to 1400 MW because the increased capacity provides a benefit to consumers.

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59 Capex IM, clause 1.1.5(2).

60 Transpower notified us of its intention to plan a staged major capex project on 23 April 2025, available here.

61 The proposal has a $66.3 million positive net market benefit relative to the like for like replacement option (the three DC cable 1200 MW option). *Transpower New Zealand Ltd*, HVDC Stage 1 MCP Main Overview, Table 4, p.20, available here.

62 *Transpower New Zealand Ltd*, HVDC Stage 1 MCP Main Overview, Table 2, p.6, available here.

B11 The HVDC link provides significant benefit to consumers. Mostly it facilitates access to lower cost South Island generation into the North Island wholesale electricity market. It is also used to provide energy support into the South Island when there are low hydro inflow years.

B12 In its proposal Transpower summarises the importance of the HVDC link stating that:[63]

> The High Voltage Direct Current (**HVDC**) link is one of the most critical components of New Zealand's electricity system. It transports electricity between the North and South Islands and in doing so enables the efficient sharing of resources and supports a more resilient and renewable powered electricity grid. As New Zealand continues to grow and electrify, the HVDC link will play an increasingly essential role enabling that transition

B13 The justification of the three-cable replacements is based on asset condition analysis. The justification for the increase in HVDC link capacity has been based on economic analysis using demand and generation scenarios to identify if forecast wholesale electricity market prices are likely to benefit from link capacity being increased from 1200 MW to 1400 MW.

B14 We discuss Transpower's demand and generation assumptions in more depth when we review Transpower's application of the investment test but agree with Transpower's view about potential new generation such as solar, and the modelling approach it has taken in this MCP.

B15 In summary, we agree that the proposed investment in HVDC Stage 1 MCP meets the requirements of clause D1(1)(b) of Schedule D of the Capex IM, in that it is required to meet the economic limb of the GRS.

### Transpower has met the notification requirements under the Capex IM

B16 We are satisfied that Transpower's notification of 23 April 2025 complied with clause 3.3.1(1) of the Capex IM.[64] This is because the notification advised us of Transpower's intention to plan to submit the HVDC Stage 1 MCP.

B17 Transpower's notification also proposed the matters required under clause 3.3.1(2) of the Capex IM. On 22 May 2025, we acknowledged Transpower's Notice of Intention (**NOI**) setting the matters that we needed to seek agreement on including the long-list and short-list consultations, and our view that it was reasonable for Transpower not to seek proposals on NTSs.[65]

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63 *Transpower New Zealand Ltd*, HVDC Stage 1 MCP Main Overview, Section 1, p.3, available here.

64 *Transpower New Zealand Ltd*, Letter of Notification under clause 3.3.1(1), available here.

65 *Commerce Commission*, letter to Transpower agreeing matters under clause 3.3.1(2) of the Capex IM, available here.

B18 Under clause 3.3.1(7) of the Capex IM, the Commission and Transpower must regularly review whether the consultation programme remains appropriate and reasonable. In an MCP process may amend the consultation programme to achieve that outcome.

### Transpower has satisfied the consultation requirements

B19 The Capex IM requires Transpower to consult with interested parties on the following matters when preparing an MCP:[66]

B19.1 investment need;

B19.2 each demand and generation scenario variation;

B19.3 key assumptions;

B19.4 a long-list of options to meet investment need; and

B19.5 a short-list of investment options to meet investment need.

B20 Transpower's long-list consultation must:[67]

B20.1 describe the relevant investment need and its links to other relevant documents, such as the integrated transmission plan;

B20.2 set out the relevant demand and generation scenarios;

B20.3 specify any non-standard values or amounts of the calculation period, or value of expected unserved energy for the investment test;

B20.4 specify any non-standard discount rate that it may use for the purpose of the investment test; and

B20.5 for each option, specify whether the option is a transmission investment or an NTS, and describe its features.

B21 Transpower's short-list consultation must:[68]

B21.1 describe the relevant demand and generation scenarios to be used for the investment test;

B21.2 provide information on the relevant key assumptions;

B21.3 describe each investment option, including its features, submissions on the option from the long-list consultation, and likely electricity market benefit or cost elements and project costs; and

B21.4 describe Transpower's preliminary application of the investment test.

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[66] Capex IM, clause I1.
[67] Capex IM, clause I2.
[68] Capex IM, clause I3.

B22 In its NOI to the Commission Transpower stated that:[69]

> We first consulted on HVDC capacity options during our Net Zero Grid Pathways (**NZGP**) long-list consultation in August 2021. Throughout 2024 we have been engaging with stakeholders regarding the future of the HVDC link and the condition based issues affecting the existing cables. Given the limited options available to address the investment need, we propose that it is reasonable to exclude the Long-list consultation (as specified in Schedule I) and instead we propose proceeding directly to the short-list consultation in accordance with clause 8.1.3(2)(b).

B23 In addition, the long-list consultation phase is also focussed on seeking NTS as potential alternatives to meet the investment need. Transpower in its NOI note that:[70]

> Non-transmission solutions (**NTS**) will not be considered as investment options in the investigation. Given the condition based need to replace the HVDC cables, the scale of the load and the obsolescence of the control system, we believe that NTS are unlikely to provide a viable alternative to retaining an operational HVDC link between the North and South Island electricity networks.

B24 We agreed with Transpower's view about the long-list consultation and its view of the applicability of NTS in this proposal. In our 22 May 2025 NOI response to Transpower we set out the matters for agreement with Transpower under clause 3.3.1(3) that included the requirement that Transpower only needed to carry out a short-list consultation.

B25 Transpower carried out its short-list consultation between May and June 2025.[71]

B26 Transpower prepared its revised short-list of investment options using a number of criteria. The criteria included that the investment option is:[72]

B26.1 fit for purpose;

B26.2 technically feasible;

B26.3 practical to implement;

B26.4 consistent with GEIP;[73]

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69 *Transpower New Zealand Ltd*, Letter of Notification under clause 3.3.1(1), p.4, available here.

70 *Transpower New Zealand Ltd*, Letter of Notification under clause 3.3.1(1), p.3, available here.

71 *Transpower New Zealand Ltd*, HVDC link upgrade programme - Short-list consultation webpage, available here.

72 *Transpower New Zealand Ltd,* HVDC Link Upgrade Programme MCP Short-List Consultation, Attachment 4 – Short-list of investment options, available here.

73 Capex IM, under clause 1.1.5(18, the definition of 'good electricity industry practice' is that specified in clause 1.1(1) of the Code, which is "the exercise of that degree of skill, diligence, prudence, foresight and economic management, as determined by reference to good international practice, which would reasonably be expected from a skilled and experienced asset owner engaged in the management of a transmission network under conditions comparable to those applicable to the grid consistent with applicable law, safety and environmental protection. The determination is to take into account factors such as the relative size, duty, age and technological status of the relevant transmission network and the applicable law."

B26.5 ensures system security will be maintained; and

B26.6 the indicative capital cost is not prohibitive when compared to another investment option with the same or similar benefits.

**Our evaluation of Transpower's consultation**

B27 In our review of the Transpower consultation process we are most interested in how Transpower has used stakeholder feedback to inform its proposal. We are guided by the Capex IM in this review, specifically how arguments raised by submitters "were taken into account when determining the investment options and applying the investment test."[74]

B28 These submissions provide information to Transpower about assumptions, demand and generation forecasts and transmission alternatives. In our review of an MCP we must be satisfied that the data, analysis and assumptions underpinning the proposal is fit for purpose for us to exercise our powers under Part 4 of the Commerce Act, including the consideration as to the accuracy and reliability of data and the reasonableness of assumptions and other matters of judgement.[75]

B29 Transpower asked ten specific questions in its short-list consultation and received twelve submissions.[76]

B30 Submitters were generally supportive of the process Transpower had used to refine its long-list to the short-list of investment options, and the criteria it used to do so.

B31 In general submitters supported the investment need highlighting the economic impact of the HVDC link (Meridian) and the alignment of link capacity with New Zealand's decarbonisation goals (Fonterra). Most submissions identified issues related to the Transpower assumptions, modelling and the need for the 4th cable.

B32 We have reviewed those submissions and how Transpower has addressed the key points raised in the submission material it received in its proposal.[77]

### Generation and modelling assumptions

B33 Some submitters provided some focussed information about how Transpower had modelled generation in the scenarios it uses to quantify the market benefits to justify the link capacity increasing from 1200 MW to 1400 MW. The generation assumptions have a direct impact on the net market benefits of the proposal.

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74 Capex IM, Schedule G clause G7.

75 Capex IM, clause 6.1.1(2)(c).

76 *Transpower New Zealand Ltd*, HVDC link upgrade programme - Short-list consultation, available here.

77 *Transpower New Zealand Ltd*, HVDC Link Upgrade Programme - Summary of short-list consultation submissions and responses, July 2025, available here.

B34 Fonterra noted that the:[78]

B34.1 "recent announcement of the staged decommissioning of the Whareroa and Edgecumbe cogeneration plants, the decommissioning data in Table 5 in Attachment 1 should reflect a 2026 date, not 2033 and 2038;"

B34.2 "geothermal assumptions of re-injection and cost reduction in the Growth scenario do not seem appropriate when compared to the other scenarios. Re-injection and cost reduction assumptions should be included in the Environmental and Disruptive scenarios"; and

B34.3 "baseload gas thermal generation plant availability post-2030 should be revisited as there remains a strong likelihood that baseload gas thermal plant will be fully decommissioned by 2030."

B35 The Business Energy Council (**BEC**) asked whether demand-side response would be a more cost-effective solution than the HVDC capacity upgrade to 1400 MW.[79]

B36 Following our review of the proposal and Transpower's summary of submission document we could find no substantial discussion of the Fonterra and BEC submission points raised. We sent Transpower RFIs to address these points and discuss the Transpower response in Attachment D.[80]

B37 Vector questioned Transpower's assumptions about utility scale battery operation in its modelling. Vector noted that utility scale batteries have a "finite energy and are often deployed to chase arbitrage revenue, cycling between charging and discharging as market conditions shift". Vector was unclear if "such assets could – or would – be held continuously in reserve, especially during peak periods when their energy may already be committed".[81]

B38 Transpower addressed the Vector battery operational assumption query in its summary of submission document noting that it hadn't assumed all "utility scale batteries are continuously available to provide instantaneous reserve across all trading periods. Instead, batteries are dispatched based on co-optimisation of energy and reserves reflecting how the electricity market operates in real time."[82]

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78 *Fonterra*, HVDC Stage 1 MCP short-list consultation submission, p.1, available here.

79 *BEC*, HVDC Stage 1 MCP short-list consultation submission, p.4, available here.

80 RFI004 - HVDC Stage 1: Major Capex Proposal: Demand and generation scenarios, and RFI007 - HVDC Stage 1: Major Capex Proposal: Short-list consultation questions.

81 *Vector*, HVDC Stage 1 MCP short-list consultation submission, pp.9-10, available here.

82 *Transpower New Zealand Ltd*, HVDC Link Upgrade Programme - Summary of short-list consultation submissions and responses, July 2025, pp.4-5, available here.

B39 Meridian queried "whether Transpower should adopt the most recent 2024 Electricity Demand and Generation Scenarios (**EDGS**) as the basis for its modelling" because in its opinion "the 2019 EDGS are out of date and contain some unrealistic assumptions". Meridian specifically highlighted two such assumptions namely:[83]

B39.1 the availability of North Island gas to support thermal generation investments in the North Island; and

B39.2 the extremely low rates of solar uptake.

B40 In its summary of short-list submissions document Transpower discussed its use of an updated 2019 EDGS and that it planned to use the 2024 EDGS in future projects. Transpower stated that:[84]

> The updated version used is based on an extensive process of updating the 2019 EDGS to reflect future views of electricity demand and generation that occurred in 2020 and 2021. This included several online panel discussions with industry experts and formal consultation. We subsequently reviewed and updated the scenarios based on more recent information. Following the release of the 2024 EDGS we reviewed the demand growth paths at a high level. Our view is that they are broadly like those that we have used. On that basis we consider the existing scenarios we have used are reasonable and appropriate for assessing this project.

B41 We are generally satisfied with Transpower's approach to developing its scenarios. It consulted widely on its assumptions, seeking industry input into the timing and location of specific generators it had modelled. However, the Meridian submission highlights that it still doubts the appropriateness of some generation assumptions and the impact of these. In its proposal Transpower did not specifically respond to Meridian's specific points.

B42 Given the capacity upgrade aspect of the proposal is highly dependent on the generation (and to an extent demand) scenarios, and the timing and location of modelled generation, we sought additional information from Transpower on this and other scenario modelling assumptions using a Request for Information (RFI).[85]

B43 We discuss the Transpower RFI response in Attachment D.

### AC system upgrades

B44 Vector and Contact questioned Transpower's AC system upgrade assumptions and plans.

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83 *Meridian*, HVDC Stage 1 MCP short-list consultation submission, p.2, available here.

84 *Transpower New Zealand Ltd*, HVDC Link Upgrade Programme - Summary of short-list consultation submissions and responses, July 2025, pp.4-5, available here.

85 RFI004 - HVDC Stage 1: Major Capex Proposal: Demand and generation scenarios.

B45 Vector noted that a core modelling assumption appeared to be the treatment of HVDC south transfer specifically that "Transpower's modelling allows power to flow south at the full rating of the proposed four-cable link. Yet, in practice, the HVDC link can send no more than 950MW in that direction until a separate package of AC-grid upgrades is delivered".[86]

B46 Further that "Transpower acknowledges that those other investments would be needed before the full 1,400MW capacity can be used" and "requests that Transpower re-run the dispatch model with the 950MW south-bound constraint reinstated and publish the resulting changes in both net benefits and the indicative benefit-based charges".[87]

B47 Contact noted that it was "critical that the upgrades to increase the AC system capacity are completed prior to the HVDC upgrade to realise the full benefit of option 3", specifically:[88]

B47.1 "Haywards to Whakamaru (including the Wairakei Ring) to enable the transfer of additional power flowing north to northern load centres": and

B47.2 "Lower South/Southland region to avoid stranding existing and planned generation in that region that will utilise the additional HVDC north capacity".

B48 In its summary of submissions document, Transpower state that the Vector understanding of HVDC south flow capability was incorrect. Transpower confirmed that "the effective southward limit remains constrained by the AC transmission system in the lower North Island – not by the HVDC system itself" and that its modelling ensures "that the benefits assessment reflects the physical limitations of the AC network and avoids overstating benefits".[89]

B49 Transpower also note that additional AC network upgrades may unlock additional benefits but that these are "outside the scope of the current HVDC proposal – and any costs and benefits related to these additional works are not included. Any investigation into relieving these AC constraints would be considered as part of a separate project".

B50 We note that the first stage of the NZGP project involved significant capacity upgrades between Haywards and Whakamaru, and the recently completed Clutha Upper Waitaki Lines Project (**CUWLP**) would relieve a capacity constraint in the Lower South Island region. If Contact has specific projects in mind that would lead to constraints, then it needs to engage with Transpower to have these constraints relieved in a timely manner and if it is economic to do so.[90]

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86 *Vector*, HVDC Stage 1 MCP short-list consultation submission, pp.2-3, available here.

87 *Vector*, HVDC Stage 1 MCP short-list consultation submission, para 11, p.2, available here.

88 *Contact*, HVDC Stage 1 MCP short-list consultation submission, p.1, available here.

89 *Transpower New Zealand Ltd*, HVDC Link Upgrade Programme - Summary of short-list consultation submissions and responses, July 2025, p.11, available here.

90 *Transpower New Zealand Ltd*, Net Zero Grid Pathways project available here, and the Clutha Upper Waitaki Lines Project available here.

B51 While not directly related to the proposal, Vector discussed the need for other grid investments, not related to the HVDC proposed upgrade, and whether Transpower's priorities were reasonable. Vector noted that the Upper North Island (**UNI**) region needed to be upgraded to facilitate renewable energy development and questioned if the "costs and benefits are truly being considered from a whole of system perspective and whether resilience is being valued appropriately".[91]

B52 We understand that Transpower is currently investigating a number of transmission upgrades in the UNI region. However, these are projects to meet demand growth. The Vector point is more likely about Transpower's lack of coordinated grid wide view of how it identifies, prioritises and economically justifies grid upgrades to facilitate new generation and potential generation.

B53 While Transpower has demonstrated that the 4th cable is economically justified, the general question that a grid wide generation driven transmission plan is missing, is valid. A grid wide plan would ensure that multiple generation driven transmission upgrade projects could be progressed in stages simultaneously based on updated knowledge of likely generation projects to retain maximum optionality, instead of Transpower's present bottom-up approach.

B54 We hold the same view and will be discussing this with Transpower about taking a more grid wide approach to its transmission upgrades to enable renewables generation, rather than taking a project-by-project bottom-up view.

### The necessity of the proposed 4th cable and staging the 4th cable

B55 In its short-list submission Vector submitted that the 4th cable could be deferred as it would retain optionality. Vector stated it "does not claim that these option value benefits would necessarily outweigh the economies Transpower has identified. They may or may not. What matters is that those benefits are real and should be included in the assessment".[92]

B56 In its analysis, Transpower addressed this point concluding the 4th cable deferred option was not short-listed because it will "result in higher overall costs and lower net benefits compared to installing all four cables together" because:[93]

B56.1 "future procurement of a single HVDC submarine cable may be unfeasible or highly risky due to limited global supply and increasing demand";

B56.2 "if staged, the fourth cable would still need to be ordered now, shipped to New Zealand, and stored – incurring significant handling, storage, and risk management costs"; and

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[91] *Vector*, HVDC Stage 1 MCP short-list consultation submission, pp.4-5, available here.

[92] *Vector*, HVDC Stage 1 MCP short-list consultation submission, p.2, available here.

[93] *Transpower New Zealand Ltd,* HVDC Link Upgrade Programme MCP Short-List Consultation, Attachment 4 – Short-list of investment options, p.11, available here.

B56.3 a “second vessel mobilisation would further increase costs (including additional outages), effectively negating any option value.”

B57 Vector also noted that "there is a distinct possibility that the fourth cable may prove to be unnecessary – at least for some of the investment’s lifespan. For example, if North Island demand or renewable development grows more slowly than Transpower’s ‘Growth’ or ‘Environmental’ scenarios, the additional 200 MW could remain under-used for many years while consumers, including Vector’s, foot the bill for it".[94]

B58 Further Vector note that the marginal benefit of the additional HVDC capacity might be met by other means stating that “the incremental cost of the final 200MW would be well below that of the first 1,200MW, the marginal benefit would also likely be smaller. If the additional capacity is seldom, if ever, used - or if other solutions can meet the same underlying demand closer to where it arises – the additional cable may not represent value for money despite its lower unit cost”.[95]

B59 While Transpower briefly discuss this deferred 4th cable option, we sought additional information about a number of cable replacement and upgrade options. We asked Transpower to provide the following:

B59.1 economic analysis of the 4-cable vs a 3-cable replacement option showing it provides a net market benefit; and

B59.2 economic analysis of an HVDC cable run to failure and repair on failure option.

B60 Our view is that the ‘cable run to failure’ option is a credible alternative that needs to be publicly discussed to demonstrate that the proposal is the best economic outcome for consumers and the value of the HVDC link.

B61 While we note that in some areas there is no ability to repair the HVDC cables if these are damaged, in other areas this is not the case. This reparable vs. not reparable cable section analysis should feed into an assessment of HVDC link economic analysis which should be probabilistic and not deterministic.

B62 We requested that Transpower provide us with analysis of a ‘cable run to failure’ scenario and discuss this in our review of Transpower’s investment test analysis, alongside our review of the proposed 200 MW HVDC capacity upgrade in Attachment D.

### Termination station and HVDC overhead line issues

B63 Meridian raised questions about Transpower’s plans for the HVDC cable termination stations.

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94 *Vector*, HVDC Stage 1 MCP short-list consultation submission, para 7, p.2, available here.

95 *Vector*, HVDC Stage 1 MCP short-list consultation submission, para 5, p.2, available here.

B64 Meridian sought further details about the termination station project scope noting that "the industry has experienced several outages caused by salt spray buildup on insulators, requiring urgent remedial outages. Meridian queries whether consideration been given to relocating the termination stations further inland to reduce exposure to coastal conditions and mitigate this recurring risk."[96]

B65 NZ Steel referred to an outage incident that occurred on the HVDC overhead line stating that the "overhead, over-land part of the link that was compromised about five years ago" and "highlighted deficiencies with Pole 2 and Pole 3 conductors in close proximity over difficult terrain" that necessitated a "shut-down of both poles."[97] NZ Steel wanted to understand if Transpower had any plans to mitigate the issue that resulted in that outage in this proposal.

B66 In its summary of short-list submissions Transpower responded that it planned to locate the new termination station adjacent to the existing buildings. To mitigate the salt spray buildup issue noted by Meridian, Transpower plans to:[98]

- B66.1 use of more pollution-resistant equipment, including longer and larger HV bushings;
- B66.2 application of anti-salt buildup coatings; and
- B66.3 installation of permanent washdown facilities and provision for more frequent cleaning.

B67 Transpower is also investigating the "effectiveness of a seaward-facing screen to protect roof bushings" and "will continue to assess the cost benefit trade-offs of further relocating the termination station as the project progresses."[99]

B68 As part of our review, we sought additional information on the options Transpower is considering relocating the termination station, as this impacts the costs we approve, and how it considered the NZ Steel submission point. We discuss this in Attachment D.

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96 *Meridian*, HVDC Stage 1 MCP short-list consultation submission, p.1, available here.

97 *NZ Steel*, HVDC Stage 1 MCP short-list consultation submission, p.1, available here.

98 *Transpower New Zealand Ltd,* HVDC Link Upgrade Programme MCP Short-List Consultation, Attachment 4 – Short-list of investment options, pp.10-11, available here.

99 *Transpower New Zealand Ltd,* HVDC Link Upgrade Programme MCP Short-List Consultation, Attachment 4 – Short-list of investment options, p.11, available here.

### Operational limit and project related outages

B69 Meridian, while supporting raising the HVDC capacity to 1400MW sought clarification regarding "whether the proposed investments would alleviate any of the current operational limitations that are reliant on cable discharge times and other physical traits, on the HVDC – such as the reserve sharing limits" and that it "would be useful to understand whether any control system improvements are included in the scope, alongside the planned capacity upgrade".[100]

B70 In its summary of short-list submissions Transpower responded to Meridians clarifying questions stating that:[101]

B70.1 "Pole 2 is currently limited to 500 MW due to its connection to a single cable, whereas Pole 3 is connected to two cables. With the installation of a fourth cable, the limiting factor will shift to the rating of the Pole 2 converter transformers, which is 700 MW";

B70.2 "increasing the Pole 2 15-minute overload capability to 150% (840 MW) will ease current reserve sharing limitations between Pole 2 and Pole 3 and delivers significant benefits, which have been quantified in our analysis";

B70.3 "the new cables will have the same discharge performance requirements as the existing cables they are replacing. These discharge times are designed to reduce electrical stress and maximise cable lifespan – shortening the discharge time would reduce asset life"; and

B70.4 the plan is to include "round power functionality within the scope of the new control system, enabling seamless and flexible transfer capability in either direction — from South to North or vice versa".

B71 We consider that Transpower adequately addressed the points raised by Meridian.

### Summary

B72 While Transpower addressed the majority of the points raised in the short-list consultation process in its proposal, there were some that it didn't. Where this was the case we sought additional information using the RFI process, and we discuss Transpower's response to these RFIs throughout our review of the proposal.

B73 Following our review of the Transpower short-list consultation submissions and how it has addressed the points raised in those submissions, we are satisfied with Transpower's approach to consultation in the HVDC Stage 1 MCP and that it meets the Capex IM requirements.

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[100] *Meridian*, HVDC Stage 1 MCP short-list consultation submission, p.2, available here.

[101] *Transpower New Zealand Ltd*, HVDC Link Upgrade Programme - Summary of short-list consultation submissions and responses, July 2025, p.14, available here.

### Transpower has satisfied the information requirements under the Capex IM

B74 The Capex IM sets out the information that Transpower needs to provide in an MCP.[102] The MCP and the attachments that Transpower provided for this purpose are listed in Table B1 below.[103]

B75 Transpower provided a table mapping the information required under the Capex IM with the information provided in its MCP and the attachments.

**Table B1 The HVDC Stage 1 MCP and attachments**

| **Document provided by Transpower in its proposal** |
|---|
| HVDC Stage 1 Major Capex Proposal – Main Overview Document September 2025 |
| Attachment 1: Compliance with the Capex IM |
| Attachment 2: Need, Demand and Generation Scenarios |
| Attachment 3: Cable Condition Assessment Report |
| Attachment 4: Short-list of investment options |
| Attachment 5: Costing Report |
| Attachment 6: Benefits modelling |
| Attachment 7: Investment Test |
| Attachment 8: Stakeholder Engagement |
| Attachment 9: Transmission Pricing Methodology (TPM) and Indicative Pricing Impacts |
| Attachment 10: Chief Executive Certification |
| Attachment 11: GHD HVDC Cable Replacement Independent Expert Report |

B76 We have reviewed the MCP and the attachments against clause G1 to G8 of Schedule G of the Capex IM and are satisfied that Transpower has met the information requirements.

### Transpower satisfied the certification requirements under the Capex IM

B77 Clause 9.2.1 of the Capex IM requires that, before Transpower submits a MCP to us, Transpower's CEO must certify the MCP according to requirements in that provision.

B78 Transpower provided a certificate signed by its CEO.[104]

B79 We reviewed this certificate against clause 9.2.1 of the Capex IM and we are satisfied that it meets the relevant requirements.

[102] Capex IM, Schedule G.
[103] The HVDC Stage 1 MCP proposal documents are available here.
[104] *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 10 – CEO certification, available here.

**The Transpower IMs are not relevant to our review of Transpower's HVDC Stage 1 MCP proposal**

B80 As noted in Attachment A, the Transpower IMs provide for recoverable costs associated with major capex projects, and the revenue impact of such projects we have approved.[105]

B81 The treatment of recoverable costs and the revenue impact of the major capex are not relevant to our review of Transpower's proposal. However, if we approve the proposal:

B81.1 recoverable costs associated with an NTS will be recoverable by Transpower as per clause 3.1.3(1)(d) of the Transpower IM; and

B81.2 the revenue impact of approved major capex will be subject to a price-quality path reconsideration as per clause 3.7.7(4).

## Delivering the HVDC Stage 1 MCP as proposed will promote the purpose of Part 4 of the Act

B82 Under the general evaluation criteria, we must consider "the extent to which what is proposed will promote the purpose of Part 4 of the Act".[106] Alongside the investment test under Schedule D, we consider this is an important test for expenditure proposed under the Capex IM.

**The purpose of Part 4 of the Act**

B83 The purpose of Part 4 of the Act is to promote the long-term benefit of consumers in markets where there is little or no competition, and little or no likelihood of a substantial increase in competition.[107] 'Competition' means 'workable or effective competition'.[108]

B84 To promote workable or effective competition that is in the long-term benefit of consumers, we must promote outcomes in regulated markets that are consistent with outcomes produced in workably competitive markets.

B85 Section 52A(1) of the Act specifies the following four outcomes produced in such markets that we must promote, so that regulated suppliers, including Transpower:

B85.1 have incentives to innovate and invest;

B85.2 have incentives to improve efficiency and provide services at a quality that reflects consumer demands;

B85.3 share the benefits of efficiency gains with consumers, including through lower prices; and

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105 Transpower IM, clauses 3.1.3(1)(d) and 3.7.4(4).
106 2012 Capex IM Reasons paper, at para 1.3.7.
107 Commerce Act 1986, s 52A(1).
108 Commerce Act 1986, s 3(1).

B85.4 are limited in their ability to extract excessive profits.

**The HVDC Stage 1 MCP will promote the purpose of Part 4 by providing for Transpower to deliver the right investment at the right time**

B86 The purpose of Part 4 of the Act, particularly as set out in section 52A(1)(a) and (b), will be promoted by delivering the right investment at the right time to meet an identified need.

B87 The Capex IM requires Transpower to apply the investment test to select the investment option with the lowest expected net market cost, or highest expected net electricity market benefit as the proposed investment.[109] This can include a qualitative assessment to take account of associated unquantified benefits, or cost elements, in certain circumstances.[110]

B88 The investment test under Schedule D of the Capex IM, is a net electricity market benefit test that uses a range of future scenarios to identify the investment option, with the lowest expected net market cost in meeting the GRS, or highest expected net market benefit to meet forecast demand. The test is designed to identify the most efficient investment option as the proposed investment in a MCP.

B89 We consider the investment test enables the selection of the right investment based on the available information, and corresponding assumptions about the future composition of the power system.

B90 Based on our evaluation in Attachments C and D, we are satisfied Transpower has proposed the right transmission investment options to meet the investment need.

**Delivering the HVDC Stage 1 MCP is necessary to meet the economic limb of the GRS**

B91 Consistent with section 52A(1)(b) of the Act and the Capex IM, a proposed investment must be the investment option with the highest expected net electricity market benefit when compared with alternative options, unless it is designed to meet the deterministic limb of the GRS.[111]

B92 Following our review of the proposal, we are satisfied Transpower's proposed investment to enhance HVDC capacity from 1200 MW to 1400 MW meets the economic limb of the GRS and also has the highest expected net electricity market benefit when compared with alternative investment options.

[109] Capex IM, clause D1.
[110] Capex IM, clause D1(1)(c).
[111] Capex IM, clauses D1(1)(b) and D1(1)(c)(i).

B93 Transpower has justified the need and investment timing for the replacement of the existing cable assets using condition assessment analysis and tested various replacement scenarios, including a 'repair on fail' option. In these options, Transpower has reasonably demonstrated that the proposal provides the highest electricity net market benefit to consumers.

## The data, analysis, and assumptions underpinning what is proposed are fit for purpose

B94 Schedule G of the Capex IM sets out the information that Transpower needs to provide in a MCP.

B95 Transpower's HVDC Stage 1 MCP contains the following documents:[112]

B95.1 Overview document: the main proposal overview document provides an overview of the MCP, including the driver of investment need, a consolidated summary of the analysis Transpower has performed to support its application, and the conclusions it has reached.

B95.2 Attachment 1 (Compliance with the Capex IM): summarises where in the proposal Transpower has addressed the Capex IM requirements.

B95.3 Attachment 2 (Need, demand and generation scenarios): describes the investment need and outlines the demand and generation scenarios used in the MCP supporting analysis and application of the Investment Test.

B95.4 Attachment 3 (Cable condition assessment): describes how Transpower has analysed and justified the replacement of the existing cables.

B95.5 Attachment 4 (Short-list of investment options): describes how Transpower developed its short-list development plans from the long-list options and the criteria it used to do this.

B95.6 Attachment 5 (Costing): provides an overview of Transpower's assessment of investment option capital costs;

B95.7 Attachment 6 (Benefits modelling): describes how Transpower has calculated the benefits of the investment options considered using the benefit modelling approach.

B95.8 Attachment 7 (Application of the investment test): provides an overview of our HVDC Stage 1 MCP options analysis and the approach to the investment test. It includes the application of the investment test and identifies the preferred option.

B95.9 Attachment 8 (Stakeholder engagement): provides a summary of Transpower's consultation and outlines how stakeholder feedback has informed the proposal.

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112 The HVDC Stage 1 MCP proposal documents are available here.

B95.10 Attachment 9 (TPM and Indicative Pricing Impacts): provide an estimated increase in transmission charges based on the TPM.

B95.11 Attachment 10 (Chief Executive Officer (CEO) Certification): provides certification from Transpower's CEO that the information complies with the relevant provisions of the Capex IMs.

B95.12 GHD Independent Expert Review report: provides a pre-proposal submission review of Transpower's MCP to assess the investment need, procurement strategy, economic evaluation, and costs.

B95.13 Summary of short-list submissions that provides a summary of the key issues raised and how these are addressed in the proposal.

B96 When assessing a MCP proposal, we must be satisfied that data, analysis, and assumptions underpinning what is proposed allows us to make our decision.

B97 As we evaluated the HVDC Stage 1 MCP, we sought additional information from Transpower using a RFI process in accordance with clause 3.3.5(4) of the Capex IM.

B98 Table B2 lists additional information that Transpower provided to assist our analysis.

**Table B2 Additional information provided by Transpower**

| Document short name | Subject |
|---|---|
| **RFI001** | HVDC cable replacement |
| **RFI002** | Cable termination station |
| **RFI003** | Benmore filter and Pole 2 Short-Term Overload scheme |
| **RFI004** | Demand and generation scenarios |
| **RFI005** | Investment test analysis |
| **RFI006** | Capital costs |
| **RFI007** | Short-list consultation questions |
| **RFI008** | Resource Management Act and other consents |
| **RFI009** | Outage costs |
| **RFI010** | Exchange rate and financing costs |
| **RFI011** | P50 cost estimates |
| **RFI012** | Fourth cable deferral economic analysis |
| **RFI013** | Liquid Natural Gas (**LNG**) plant impact on investment test |
| **RFI014** | Cost risk component in $ nominal terms |

B99 Having reviewed the HVDC Stage 1 MCP proposal material and the additional information that Transpower has provided, we are satisfied that the data, analysis, and assumptions underpinning what is proposed, are fit for purpose, reliable and accurate.

B100 We consider that the information provided to us is sufficient for us to make our draft decision on the HVDC Stage 1 MCP.

## The GHD Independent Expert Review

B101 Prior to submitting the HVDC Stage 1 MCP to us, Transpower engaged GHD Limited (**GHD**) to carry out a pre-submission independent review of the HVDC link upgrade.[113]

B102 We have used the GHD report to assist us in our review of the proposal in a similar way to how we use pre-submission verification when we assess Transpower Regulatory Control Period (**RCP**) 5-year reset proposals.

B103 The conclusions of the GHD report resulted in Transpower splitting the HVDC link upgrade into two proposal stages. The second stage is likely to be submitted to us near the end of 2026. This will give Transpower time to better understand the scope and costs associated with an HVDC control system upgrade, and whether it needs to remove the existing cables.

B104 GHD tested may aspects of the proposal that included technical need, project cost estimates and procurement issues that may affect delivery risk. We have used these conclusions to help direct our review of the key matters in the proposal, such as capital cost estimates, investment need and the scope of key outputs in the proposal.

B105 The terms of reference of this review were agreed by both Transpower and the Commission and requested that GHD evaluate whether Transpower's HVDC MCP's capex, opex (including the methods undertaken to prepare those costs), and key assumptions are consistent, and represent the actions of a prudent electricity transmission services supplier, having regard to GEIP.[114] We also agreed a set of evaluation criteria to guide GHD in its review.[115]

B106 GHD were tasked with reviewing the following components of the HVDC link upgrade programme, including the:

B106.1 HVDC 350kV submarine and land-based cables;

B106.2 civil and building works for new termination stations;

[113] GHD is a "global, multidisciplinary professional services network providing clients with integrated solutions across advisory, digital, engineering, architecture, environmental and construction."

[114] *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 10 – GHD Independent review – HVDC Link Upgrade Programme, Appendix B, available here.

[115] *GHD*, Independent Review - HVDC Link Upgrade Programme, Appendix B-1, pp.63-64, available here.

B106.3 HVDC control system;

B106.4 removal of existing 350kV cables; and

B106.5 construction of a new cable storage facility.

B107 Finally, GHD were asked to identify any other information not included in the HVDC MCP that would assist us in our review.

**GHD review key findings – technical evaluation**

B108 In its technical evaluation, GHD tested whether Transpower had made the case for the investment need for the suite of investments it is proposing. We set a summary of these findings.

### HVDC cables and associated works

B109 GHD concluded that, overall, the proposed cable investments align with good industry practice with the capacity increase justified based on future load growth and generation developments. The proposed programme is "technically feasible and will be implemented in stages to mitigate outage risks."[116]

B110 The decision to replace the existing cables is based on cable health models, electrical tests on the cables and visual inspections to determine cable condition. HVDC cable design life is understood to be 40 years, which is consistent with other HVDC installations and HVDC cable replacement projects around the world.[117]

B111 GHD also tested the cable replacement date proposed by Transpower and concluded that:[118]

B111.1 "inspections and asset health data confirm that replacement will be necessary by 2032" and that "extending their operation beyond this date significantly raises the risk of failure";

B111.2 if cable repair is feasible, it would "require a six-to-18-month response period should failure occur after 2031 although the risk the cables cannot be repaired grows as they age";

B111.3 "Transpower provided an additional analysis of the likelihood and impact of a cable failure under a do-minimum option where Transpower would attempt to repair cables as they fail. The modelling suggests that in cumulative terms, there is a 37-50% chance that an individual cable will fail by 2035, and there is risk that more than one cable will fail by that time";

116 *GHD*, Independent Review - HVDC Link Upgrade Programme, p.iv, available here.

117 *GHD*, Independent Review - HVDC Link Upgrade Programme, Section 5.1.2.1, p.30, available here.

118 *GHD*, Independent Review - HVDC Link Upgrade Programme, p.ii, available here.

B111.4 "By 2031, the annual probability-adjusted economic cost of cable outage and repairs is estimated at $10 million to $170 million, dependent on whether cables are repairable."; and

B111.5 "The optimal economic time to replace the cables based on the discounted cashflows of economic costs of outage and repair versus a replacement cost of $620 million (for three cables, like-for-like), was between 2025 and 2039".

B112 In conclusion, GHD state that "Transpower has provided a credible explanation of the economic rationale for replacing the existing cables as well as an explanation for why the timeframe of the early 2030s is reasonable for risk avoidance and limiting economic costs".[119]

B113 GHD assessed that the existing cable termination stations currently do not meet current seismic requirements of Transpower's policy and design codes. GHD concluded that the Transpower plan to build new termination stations would minimise outage requirements, because remediating the existing structures would likely result in lengthy outages. GHD concluded that the remediation option was not economically feasible for this reason.[120]

B114 Transpower's "programme planning indicates timely completion, integrating connections and construction sequences with minimal disruption. The cost estimation was thorough, and procurement strategies are satisfactory."[121] An independent consultant, BECA, has been engaged to carry out the solution studies for the cable termination stations which is considered to be a prudent approach.

B115 For the existing cable removal GHD note that, while removal can be considered to be aligned with good industry practice, the technical and legal need to do so is yet to be determined. In GHD's opinion:[122]

> The case needs to be made for the significance of environmental adverse effects of leaving the cables in place. There are previously laid cables, no longer used, that may help in demonstrating whether the adverse effects of leaving cables in place is significant. Alternatively, what evidence is there internationally to demonstrate the scale of the negative or positive impacts of leaving cables in place.

B116 GHD conclude that Transpower is still seeking legal advice which resulted in this aspect of the HVDC link upgrade being moved to Stage 2.[123]

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119 *GHD*, Independent Review - HVDC Link Upgrade Programme, p.ii, available here.
120 *GHD*, Independent Review - HVDC Link Upgrade Programme, p.iv, and Section 5.1, pp.30-32, available here.
121 *GHD*, Independent Review - HVDC Link Upgrade Programme, p.iv, available here.
122 *GHD*, Independent Review - HVDC Link Upgrade Programme, Section 4.6, p.25, available here.
123 *GHD*, Independent Review - HVDC Link Upgrade Programme, p.v and Section 5.7, pp.40-41, available here.

B117 As part of its cable contract, Transpower is purchasing spare cable to enable it effect repairs. GHD conclude that "the existing cable store asset has been assessed as being unable to store the recommended quantities of the repair cable and has severely restricted access and loading capabilities" elaborating that "the current storage facility in Wellington has become unsuitable as the neighbouring wharf where cable would be loaded onto the cable laying vessel has been condemned and there are increasing restrictions on docking vessels next to Wellington Airport due to the height of the berthing vessel."[124]

B118 In summary, GHD has confirmed the investment need for the replacement cables, cable termination station upgrades and the new cable storage facility. These investments are considered to be aligned with good industry practice and the cable replacement specifically, consistent with replacement timing for similar projects around the world.

B119 GHD tested the option where Transpower would repair the existing cable upon failure and confirmed the Transpower view that this alternative is not economically reasonable and may in fact impose significant costs on consumers due to increased market costs (NB: a lower HVDC capacity will constrain access to cheaper South Island hydro generation and increase the need for higher cost generation being dispatched and built in the North Island. It may also increase the need for demand curtailment during peak demand periods).

### HVDC control system replacement[125]

B120 GHD noted that, in its experience, "HVDC control and protection systems typically require upgrades after eight years for IT components and after 15-20 years for other control system components due to hardware obsolescence."[126]

B121 The existing HVDC Pole 2 and Pole 3 control and protection systems were installed in 2013 and would be due for replacement between 2028 and 2033. GHD provide examples of HVDC control system project upgrades examples around the world to demonstrate that Transpower's proposed replacement date is consistent with international practice.

B122 GHD also reference international standards such as "CIGRE Technical Brochure 649 and IEC TR 62978-2017" which "reference a life of 7 years for the HMI and 12-15 years for the digital control system."[127] Upgrades are typically driven by component obsolescence and spare part availability.

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124 *GHD*, Independent Review - HVDC Link Upgrade Programme, p.v and Section 5.6, pp.39-40, available here.

125 *GHD*, Independent Review - HVDC Link Upgrade Programme, p.iv, and Section 5.3, pp.32-34, available here.

126 *GHD*, Independent Review - HVDC Link Upgrade Programme, p.iv, available here.

127 *GHD*, Independent Review - HVDC Link Upgrade Programme, p.v, and Section 5.3, p.35, available here.

B123 We did not review the control system upgrade investment need in-depth at this stage because Transpower has delayed consideration of this aspect of the proposal until Stage 2. This is to allow it to more clearly define the project scope and cost.

B124 GHD's view is that, in line with international practice, the control system will need to be upgraded around the same time as the cables are replaced. Whether this work is carried out exactly at the same time, is an economic consideration that Transpower will need to justify with analysis in its Stage 2 proposal.

### Benmore filter bank[128]

B125 GHD notes that filters are required to remove harmonics from the power system which is an artifact of the conversion of AC to DC and vice versa. Harmonic limits in the power system are also set in the Code, which Transpower is required to meet.

B126 In terms of the technical investment need GHD concludes that the Benmore filter is required to ensure that harmonic limits are not exceeded during high HVDC transfer levels and that 1400 MW capacity can be fully utilised.

### Pole 2 short-term overload scheme[129]

B127 Transpower is proposing an upgrade to the functionality of the HVDC. GHD note that the "HVDC Bipole is operated at N-1 security level meaning network performance standards must be maintained for the loss of one pole. This is achieved by allowing the remaining pole to ramp up automatically to maintain dispatch bipole transfer level if the other pole has tripped. If the pole cannot ramp up high enough to maintain the dispatch bipole level, the deficit MW (shortfall) must be provided by reserve generation or interruptible load in the receiving island."[130]

B128 Transpower's proposal is to include a Pole 2 short-term overload (**STO**L) facility to reduce the reserves requirement in the North Island should a pole tripping occur. With three cables Pole 2 is constrained to 500 MW (the cable rating) but installation of a fourth cable will shift the pole outage constraint to the converter capacity of 700 MW. Implementing the Pole 2 STOL scheme will allow the short-term capacity rating of 840 MW to be accessed following a pole outage.

B129 GHD reference a feasibility study carried out by an HVDC manufacturer, ABB which concludes that a short-term rating of 840 MW (nominally 700 MW) can be achieved for 15 minutes following a pole outage. This is sufficient time for the System Operator to carry out a re-dispatch and will reduce reserve costs in the longer-term.

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128 *GHD*, Independent Review - HVDC Link Upgrade Programme, p.v, and Section 5.4, p.37, available here.

129 *GHD*, Independent Review - HVDC Link Upgrade Programme, p.v, and Section 5.5, pp.38-39, available here.

130 *GHD*, Independent Review - HVDC Link Upgrade Programme, Section 5.5, p.38, available here.

B130 GHD note that there is "suitable evidence is provided that the enhancement option is good engineering practice, and the outage provides the opportunity to implement this effectively" but notes that ABB flagged that older existing primary asset may become stressed under overload conditions and this may impact longer-term costs and replacement timing for those assets.[131]

### GHD review key findings – economic evaluation

B131 We agreed terms of reference that focussed on GHD assessing asset costs, delivery risk and procurement processes, all of which contribute directly or indirectly to the total project costs. We summarise the GHD findings on these topics.

### Capital costs

B132 GHD noted that in general there are "several elements of the cost-build up that pose potential risk" but that overall "headline cost estimates for each component appear reasonable, noting that only the cable replacement cost estimate is supported by a detailed proposal from a supplier."[132]

B133 Key points made by GHD included that:

B133.1 for the cables, proposals were received from two cable providers (three were approached) and the Prysmian offer was preferred. GHD conclude that the cable cost has been sufficiently market tested;[133]

B133.2 the cable termination station cost estimation was thorough with the costing carried out by suitably qualified specialists;[134]

B133.3 the estimated cost of $202 million for the control system replacement may be insufficient and GHD "estimate the cost to be $250-300 million for the upgrade";[135]

B133.4 the Benmore filter and Pole 2 short-term overload scheme costs do appear to be in the right "order of magnitude" but that there was no supporting evidence to underpin the estimates;[136]

B133.5 the cable storage facility costs have been estimated by a cost estimate engineer but the "level of detail does not match that provided for cable termination stations, and there is consequently a higher risk of exceeding cost estimates";[137] and

131 *GHD*, Independent Review - HVDC Link Upgrade Programme, Section 5.5, p.38, available here.
132 *GHD*, Independent Review - HVDC Link Upgrade Programme, p.iii, available here.
133 *GHD*, Independent Review - HVDC Link Upgrade Programme, Section 4.7.1, p.25, available here.
134 *GHD*, Independent Review - HVDC Link Upgrade Programme, Section 4.7.1, p.25, available here.
135 *GHD*, Independent Review - HVDC Link Upgrade Programme, p.v, available here.
136 *GHD*, Independent Review - HVDC Link Upgrade Programme, Section 4.7.1, p.25, available here.
137 *GHD*, Independent Review - HVDC Link Upgrade Programme, Section 4.7.1, p.25, available here.

B133.6 pricing years in advance for a marine salvage job such as the recovery of decommissioned cables is challenging.[138]

B134 In terms of allowances for escalation and interest, at the time of the GHD review, Transpower had included $209.2 million for inflation and interest costs. GHD note that it is six years out from when the cable laying will begin and that "costs may well rise by more than 13%, with costs of in demand electricity network infrastructure likely to rise faster".[139]

B135 This modest allowance of approximately 13% inflation across the programme by 2031 may expose the project to upside risk given market-wide supply constraints for work of this type. Transpower shoulders fuel cost, weather and metal cost risk, while civil and subcontracted works in New Zealand (30% of contract value) are provisional sums at this point.[140]

B136 GHD conclude that there is considerable price uncertainty at this early stage. Transpower has attempted to narrow the price range on each component. Using the current estimated range of potential pricing, costs for the project could range between $1 billion and more than $2 billion (NB: if the control system works and cable removal costs are included).[141]

B137 In summary, a key finding of the GHD review is that there is considerable cost risk associated with this project. The limited manufacturer pool, commodity price and inflation changes, cable route selection and weather related issues all make cable costs highly uncertain. Additionally, there are questions about the control system costs and whether cable removal is necessary. These unknowns have meant Transpower has delayed consideration of these upgrade components to a Stage 2 application.

### Procurement and delivery risk

B138 For the HVDC cables, the Transpower view of procurement lead time is considered necessary considering the global market for HVDC developments. GHD concluded that the level of cost estimate detail Transpower presently has is considered appropriate.

B139 Transpower did clarify that it plans to perform detailed cable route surveys closer to the installation date. The results of these surveys could cause variations in the data relied upon by Prysmian [the cable manufacturer], which may lead to a price and schedule variation."[142]

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138 *GHD*, Independent Review - HVDC Link Upgrade Programme, p.iii, available here.
139 *GHD*, Independent Review - HVDC Link Upgrade Programme, Section 4.7.1.1 p.26, available here.
140 *GHD*, Independent Review - HVDC Link Upgrade Programme, p.iii, available here.
141 *GHD*, Independent Review - HVDC Link Upgrade Programme, p.iii, available here.
142 *GHD*, Independent Review - HVDC Link Upgrade Programme, p.iv, available here.

B140 GHD did not identify any obvious procurement issues that would affect project delivery. It concluded that Transpower's procurement approach "combines early market engagement, competitive tendering, division of work packages for risk and commercial optimisation, and coordination between international and local contractors to ensure compliance and project success."[143]

[143] *GHD*, Independent Review - HVDC Link Upgrade Programme, p.ii, available here.

# Attachment C Evaluation of the proposal against the specific criteria

## Purpose of this attachment

C1 In this attachment we set out our evaluation of Transpower's HVDC Stage 1 MCP proposal against the specific criteria set out in Schedule C of the Capex IM, as required under clause 6.1.1(4) of the Capex IM.

## The specific criteria for evaluating a MCP

C2 There are two parts to our evaluation of the Transpower's HVDC Stage 1 MCP under Schedule C of the Capex IM, and we may use one or more of the techniques listed under clause C7. The two parts are:

C2.1 evaluating the HVDC Stage 1 MCP against specific criteria broken down as follows:[144]

C2.1.1 *investment test:* clause C1(1) requires us to evaluate whether the proposed investment satisfies the investment test in Schedule D of the Capex IM. Under clause C1(2), if the MCP relates to a staged major capex project, as is the case here, then the investment test must be satisfied for each staging project;[145] and

C2.1.2 *specific components:* clause C1(3) requires us to evaluate, to the extent applicable to the proposed investment, specific components of the proposed investment; and

C2.2 evaluating the HVDC Stage 1 MCP, having regard to the general factors under clause C2, and the specific factors relating to individual components of the HVDC Stage 1 MCP.

C3 Clause C2 requires us to have regard to at least one of the factors listed in clause C2(a) to (e) when evaluating a MCP. The factors listed in clause C2 are:[146]

C3.1 whether the proposed investment and investment options;

C3.1.1 GEIP;

C3.1.2 are technically feasible;

C3.1.3 can be implemented in terms of statutory process and regulatory consents; and

C3.1.4 can be integrated into the system and market operations;

144 Capex IM, clauses C1(1) and C1(3).
145 The results of the investment test are discussed in Attachment D.
146 Capex IM, clause C2.

C3.2 whether the estimated time to deliver the project is reasonable compared to the proposed commissioning date or completion date;

C3.3 whether key assumptions around outages are reasonable;

C3.4 the extent to which, in complying with the consultation programme or approach to consider non-transmission services (**NTS**), Transpower regards the views of interested parties; and

C3.5 the impact of the sensitivity analysis on electricity market benefit, or cost element of the proposed investment and investment options.

C4 The specific components described in clause C1(3) we must evaluate are:[147]

C4.1 the major capex allowance (**MCA**) and maximum recoverable costs (clause C3);

C4.2 approval expiry date and commissioning date assumptions (clause C4);

C4.3 major capex project outputs (clause C5); and

C4.4 major capex incentive rate (clause C6).

C5 When evaluating the specific components in clauses C3 to C6, we must have regard to at least one of the factors set out under each clause. We may also employ the evaluation techniques set out in clause C7.[148]

C6 Our evaluation of these MCP components and how we tested the HVDC Stage 1 MCP against the requirements of Schedule C are outlined below.

## Clause C1(1) – whether the MCP satisfies the investment test

C7 Our evaluation of Transpower's application of the investment test is outlined in Attachment D.

C8 In reviewing Transpower's application of the investment test, we carried out our own analysis. We took a two-step approach.

C8.1 Firstly, we looked at whether Transpower's inputs and assumptions were reasonable and met the requirements of Capex IM, and whether the preferred investment passed the investment test.

C8.2 Secondly, we cross-checked Transpower's investment test application to satisfy ourselves that components of the proposal would deliver net electricity market benefits.

[147] Capex IM, clause C1(3).
[148] Capex IM, clause C7.

C9 In reviewing the economic analysis results in Transpower's proposal, we consider Transpower has taken a robust approach in applying the investment test, and that the costs and benefits have been reasonably calculated.

C10 This proposal is a combination of capex to replace existing assets and investment to raise the capacity of the DC link from 1200 MW to 1400 MW. In our assessment we reviewed Transpower's justification for the replacement of existing assets and the timing of that replacement. We are satisfied that Transpower has made the case for the replacement capex. The economic analysis in this proposal is focussed on the justification the increase HVDC link capacity to 1400 MW. Given the HVDC link is not a core grid element, the increased capacity investment must provide a positive electricity net market benefit.[149]

C11 Following our review, we are satisfied that Transpower has proposed an investment package to ensure that the economic limb of the grid reliability standard is met. Transpower has also demonstrated that:

C11.1 the net electricity market benefits of its preferred investment option outweigh the costs of that investment option;

C11.2 that its preferred investment option provides the highest electricity net market benefit; and

C11.3 that in aggregate, Transpower's HVDC Stage 1 MCP proposal passes the investment test.

C12 In summary, our draft decision is that the proposed investment meets the investment test under Schedule D of the Capex IM. Specifically, we are satisfied:

C12.1 with the values Transpower has used for the parameters of the investment test;

C12.2 that the proposed investment has the highest positive expected net electricity market benefit of the investment options it considered; and

C12.3 that the proposed investment is robust to sensitivity analysis.

## Clause C2 – general evaluation of the MCP

C13 Under clause C2 of Schedule C, we must have regard to at least one of the factors listed in clause C2(a) to (e) when evaluating a MCP.

C14 Our analysis below sets out how we had regard to each of these factors in evaluating the MCP.

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149 The core grid elements are set out in Schedule 12.3 of the Code, available here. Clause D1(1)(b) Schedule D of the Capex IM requires that a proposed investment has a positive expected net electricity market benefit unless it is designed to meet an investment need the satisfaction of which is necessary to meet the deterministic limb of the grid reliability standards.

## Clause C2(a)(i) – the investment options considered should reflect GEIP

C15 In evaluating the MCP, we had regard to whether Transpower's proposed investment, and investment options reflect GEIP. We consider GEIP reflects the appropriate planning and performance standards of a prudent supplier.[150]

C16 We consider Transpower's transmission planning and performance standards are appropriate and have underpinned Transpower's analysis to investigate options to enhance the transmission grid to cater with the forecast load growth through to 2052.

C17 We consider Transpower has been prudent in selecting and consulting on investment options to address the investment need. Transpower has proposed an appropriate investment strategy given the need date it has identified.

C18 In our view, the investment options Transpower selected and consulted on reflect GEIP. Our draft decision is that the requirements of clause C2(a)(i) have been met.

## Clause C2(a)(ii) – are the proposed investment and investment options technically feasible

C19 The proposed investment, and the other investment options that Transpower considered in its short-list consultation, use equipment and network upgrades that are similar to those it has previously implemented. The installation and commissioning methods for these assets are well proven over the years, both locally and internationally.

C20 The HVDC cable replacement will involve international partners, both for the cable supplier and installer, that are internationally expert in HVDC project work. While the HVDC is not used in all power systems around the world it is well proven and accepted technology.

C21 We are satisfied Transpower has demonstrated the choice of well proven equipment in its short-list investment options are all technically feasible. Our draft decision is that the requirements of clause C2(a)(ii) have been met.

[150] The Capex IM uses the definition of 'good electricity industry practice' in Part 1 of the Code as: **good electricity industry practice** in relation to transmission, means the exercise of that degree of skill, diligence, prudence, foresight and economic management, as determined by reference to good international practice, which would reasonably be expected from a skilled and experienced **asset** owner engaged in the management of a transmission network under conditions comparable to those applicable to the **grid** consistent with applicable law, safety and environmental protection. The determination is to take into account factors such as the relative size, duty, age and technological status of the relevant transmission network and the applicable law.

## Clause C2(a)(iii) – are the proposed investment and investment options able to be implemented in terms of the statutory processes under the Resource Management Act 1991 (RMA), other regulatory consents, and obtaining property and access rights

C22 Transpower has proposed a number of investments some of which will involve the RMA and consent processes. The Benmore filter and STOL investments will be installed at existing substation sites, so it already has full property and access rights.

C23 However, Transpower will need to engage with the RMA process to install the undersea cables and to an extent the termination stations if these have to be relocated.

C24 In its Costing report Transpower states that:[151]

> We are actively engaging with iwi and other stakeholders. Cultural, environmental, and regulatory requirements are being integrated into our planning and consenting strategies from the outset. This project is specifically listed in Schedule 2 of the Fast track Approvals Act 2024, recognising its national significance and enabling us to apply directly for fast track consenting through an expert panel should we decide to do so. This proactive approach is intended to mitigate potential risks and ensure the project aligns with community expectations, statutory obligations and our social license to operate

C25 While Transpower has significant experience in council and RMA applications from other projects an undersea cable project is not one that the RMA process deals with regularly. We sought additional information from Transpower about how it plans to deal with the RMA. We were particularly interested if this could impact project costs and delivery.

C26 Transpower responded to our questions on this aspect of the proposal stating that has already formed an experienced in-house technical team to assist in the consenting process supported by a legal team "experienced in major infrastructure projects".[152]

C27 Transpower notes that one responsibility of the consenting team is to monitor the effect of any changes in legislation that could affect costs or the project timeline.

C28 While the majority of the project works will occur within the existing designations at Fighting Bay and Oteranga Bay some construction activities will occur outside them, such as the submarine cable route and cable storage. Transpower is confident of its ability to obtain the necessary designations for these works because "our recent project to replace an undersea telecommunications cable through Cook Strait in 2020 involved similar consenting and construction activities to that required to lay the HVDC submarine cables (albeit at a different scale)."[153]

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151 *Transpower New Zealand Ltd*, HVDC Stage 1 MCP Attachment 5 - Costing, p.21, available here.
152 Transpower response to RFI008 – RMA and other consents, p.2.
153 Transpower response to RFI008 – RMA and other consents, p.2.

C29 Transpower will access the Fast Track Approvals Act (**FTAA**) 2024 and plans to have all consents and authorisations in place by December 2027, and while the risk of delay is always possible, the FTAA narrows appeal timeframes and appeal issues are limited to points of law.

C30 Based on Transpower's response to our RFI and its experience with major project consenting processes, we are satisfied that the requirements of clause C2(a)(iii) have been met.

## Clause C2(a)(iv) – can the proposed investment and investment options be integrated into system and market operations

C31 We have tested whether the proposed investment, and investment options, can be integrated into the transmission system and the market operations. We consider this would be the case if these investments provide sufficient transmission capacity, do not incur uneconomic transmission constraints, and allow efficient dispatch of generation under normal operating conditions.

C32 The proposed investment and investment options delivering sufficient transmission capacity are directly linked with the investment need of the HVDC Stage 1 MCP, namely, to provide transmission capacity to:

C32.1 allow lower cost South Island generation to access demand in the North Island; and

C32.2 allow North Island generation to supply the South Island when there are low hydro inflows in the South Island.

C33 Some of the proposed investments are to upgrade existing assets, therefore these assets are already components of the system and market. The remainder of the investments associated with DC link capacity upgrade will be investments that Transpower can integrate into the system and market. Transpower has experience with network capacity upgrades from previous proposals and this proposed upgrade should be no different.

C34 The additional filter at Benmore will ensure the full HVDC converter capacity of 1400 MW while maintaining harmonic levels within statutory limits.

C35 The STOL investment is different in that it will allow the HVDC cables to be overloaded on a short-term basis if there is a contingent event and reduce reserve generation requirements. This will require changes to how the System Operator calculates reserve risk, but again, it is a well understood effect of DC operation.

C36 We consider the transmission upgrades in the proposed investment will meet the requirements of clause C2(a)(iv), because they are transmission investments that increase DC link capacity, and can be integrated into system and market operations.

## Clause C2(c) – are the key assumptions around outage planning reasonable

C37 Transpower notes in the proposal that it will implement its standard project delivery procedures, which also includes planning and scheduling.[154]

C38 Transpower mentions in its proposal that factors may affect its ability to deliver the required MCP outputs, specifically:[155]

> Unforeseen changes to electricity markets operations limiting our ability to secure the required system outages. This is largely outside Transpower's control, but we consider it highly unlikely to impact this project as we plan and forecast outage requirements to the market in advance.

C39 In its short-list submission, the System Operator noted that:[156]

> We note the Grid Owner should plan the HVDC outages to be at a time of year which is less likely to be impacted by operational conditions and should include some contingency in its planning to allow for the possibility some outages may not be able to proceed as planned due to operational conditions. Ideally the Grid Owner would plan these outages with a minimum lead time of 2 years. The longer than normal lead time is required to ensure the market can co-ordinate generation outages, fuel stocks, and generation patterns around such material outages.

C40 In its short-list submission Meridian wanted further information from Transpower about the outage planning aspect of the proposal. Meridian was unclear how outage costs had been factored into the proposal economics stating that "While it makes sense to minimise outage periods by combining a number of projects this may bring forward or extend outages at higher cost in the near-term".[157]

C41 While we consider Transpower is experienced in carrying out outage planning to facilitate transmission line upgrades, and that its outage planning assumptions are reasonable and consistent with previous upgrades, Transpower has not specifically addressed the question raised by Meridian. We sought additional information from Transpower about this in an RFI.[158]

C42 Transpower responded that "outages required for the HVDC cables will not materially differ between a three-cable and a four-cable solution. Therefore, these differences have not been factored into the economic analysis."[159] We consider this to be a credible assumption that simplifies the economic analysis.

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154 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 5 – Costing, pp.20-21, available here.
155 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 5 – Costing, p.21, available here.
156 *Transpower NZ Ltd as System Operator*, HVDC Stage 1 MCP short-list consultation submission, p.2, available here.
157 *Meridian*, HVDC Stage 1 MCP short-list consultation submission, p.2, available here.
158 Transpower response to RFI009 – Outage costs.
159 Transpower response to RFI009 – Outage costs, p.2.

C43 Transpower also note that the new cable termination stations will avoid extended outages that would otherwise be required if the station refurbishment option had been chosen.

C44 Following our review of the Transpower proposal and additional information, our draft decision is that the requirements of clause C2(c) have been met.

## Clause C2(d) – in complying with clause 3.3.1(9) with respect to the consultation programme or the approach to considering NTSs, did Transpower have regard to the views of interested persons

C45 Clause 3.3.1(9) of the Capex IM requires Transpower to consult interested persons in accordance with its consultation programme, and to follow its published approach for considering NTSs.[160]

C46 Under clause 8.1.3(1)(a) of the Capex IM, Transpower's consultation programme must provide for Transpower to consult prior to submitting a MCP on such matters specified in Schedule I of the Capex IM, as applicable.

C47 In its 23 April 2025 Notice of Intention (**NOI**), Transpower stated that it didn't consider NTS were applicable for this proposal. Transpower qualified this by stating that "Given the condition based need to replace the HVDC cables, the scale of the load and the obsolescence of the control system, we believe that NTS are unlikely to provide a viable alternative to retaining an operational HVDC link between the North and South Island electricity networks".[161]

C48 We responded to Transpower's NOI on 22 May 2025.[162] We agreed that, under the cl. 8.1.3(2)(b) requirements, an NTS was unlikely to provide a viable alternative to the majority of the proposed investment. The majority of the proposed investment is to replace existing assets, and the fourth cable and filters are proposed to raise link capacity from 1200 MW to 1400 MW.

C49 We also did not disagree with Transpower's view that a long-list consultation was unnecessary. In its Notice of Intention (**NOI**) Transpower argued that:[163]

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160 Capex IM, clause 3.3.1(3)(a), requires Transpower and us to use reasonable endeavours to agree a consultation programme for a transmission investment or a NTS, in accordance with clause 8.1.3. If the parties cannot agree within the specified time period, the Commission will set the consultation programme after considering the views of Transpower.

161 Transpower notified us of its intention to plan a staged major capex project on 23 April 2025, available here.

162 *Commerce Commission*, Response to Transpower 23 April 2025 Notice of Intention, 22 May 2025, available here.

163 Transpower notified us of its intention to plan a staged major capex project on 23 April 2025, available here.

C49.1 it originally consulted on HVDC capacity options during the NZGP long-list consultation in August 2021;

C49.2 throughout 2024 it engaged with stakeholders regarding the future of the HVDC link and the condition based issues affecting the existing cables; and

C49.3 there are limited options available to address the investment need which a long-list consultation is designed to identify.

C50 In its short-list submission, Vector suggested that a "non-network alternative could substitute for at least part of the capacity the fourth cable is intended to provide". Vector noted that "if the fourth cable is expected to be used only occasionally – e.g., providing additional capacity during rare events or short-lived peaks – then smaller-scale investments in batteries might still offer a more cost-effective solution. That possibility deserves to be explored".[164]

C51 The Business NZ Energy Council (**BEC**) also asked whether it would be more beneficial to consider "cheaper demand-side responses" rather than increasing link capacity.[165]

C52 In its proposal, Transpower has modelled the peak demand effects between the 1200 MW and 1400 MW capacity HVDC limits. We discuss this analysis more fully in Attachment D. However, we sought additional information from Transpower specifically to address the points raised by Vector and BEC.[166]

C53 Transpower responded to our RFI about using demand response as an alternative to increasing link capacity, and while it considered this alternative it concluded that it was unlikely for a number of reasons.

C54 Firstly, the HVDC link is a device that generally transmits bulk energy from the South Island to the North Island, and link capacity is not used for reliability purposes during peak demand periods. Transpower notes that demand management is more effective where peak demand is localised and controllable, and HVDC power flows are "determined by national market dispatch outcomes and not demand peaks".[167]

C55 Secondly, Transpower note that demand response effects are already incorporated into its modelling as deficit costs, which represents voluntary load curtailment effects.

C56 Transpower also notes that it has concluded that raising the HVDC link capacity to 1400 MW is more economic than a 1200 MW capacity link with DR because:[168]

C56.1 a 1400 MW HVDC link provides firm, long-duration capacity that demand response and/or an NTS cannot match economically;

164 *Vector*, HVDC Stage 1 MCP short-list consultation submission, p.2, available here.
165 *BEC*, HVDC Stage 1 MCP short-list consultation submission, p.2, available here.
166 Transpower response to RFI007 – Short-list consultation questions.
167 Transpower response to RFI007 – Short-list consultation questions, p.2.
168 Transpower response to RFI007 – Short-list consultation questions, p.2.

C56.2 "increasing HVDC capacity to 1400 MW delivers further benefits through reducing the requirement for instantaneous reserve (**IR**)"; and

C56.3 "the higher Pole 2 overload capability means the HVDC scheme can self-cover a greater share of its own contingency, reducing the amount of IR that must be procured from generation, and freeing up generation which would otherwise be held in standby. This provides a measurable, system-wide cost saving that demand-side measures cannot replicate".

C57 Transpower conclude its reasons for not considering DR as an alternative to increasing HVDC link capacity to 1400 MW by noting that, on the whole, industry feedback confirmed an NTS would not be viable, referencing Contact Energy's view, which was that it:[169]

> agreed that no viable non-transmission alternative exists. They noted that North Island Battery Energy Storage Systems (**BESS**) would complement but not substitute for a 1,400 MW HVDC upgrade, as batteries cannot provide the long-duration firm capacity required to cover sustained energy deficits or prolonged low-wind periods.

C58 Following our review of the proposal and additional Transpower information, we consider that Transpower has adequately considered and modelled peak demand effects.

C59 Our draft decision is that the requirements of clause C2(d) have been met.

## Clause C2(e) – the impact of the sensitivity analysis on electricity market benefit or cost elements of the proposed investment and investment options

C60 The requirements of clause C2(e) are discussed in our evaluation in Attachment D of Transpower's application of the investment test.

## Clause C3 – evaluation of the major capex allowance and maximum recoverable costs

### Evaluation of the major capex allowance

C61 Transpower has requested an MCA of $1,138.6 million ($ nominal). Table C1 summarises the components of the proposed MCA.[170]

**Table C1 Summary of the components of the HVDC Stage 1 MCP MCA**

| MCA component | MCA ($m nominal) |
|---|---|
| Supply and install four new submarine HVDC cables | 871.0 |

169 Transpower response to RFI007 – Short-list consultation questions, p.3.

170 *Transpower NZ Ltd*, HVDC Stage 1 MCP Overview, Table 1, p.5 available here.

| | |
|---|---|
| Cable termination stations replacement | 161.7 |
| Benmore filter bank | 23.8 |
| Pole 2 short-term overload scheme | 15.6 |
| New submarine cable storage facility | 14.1 |
| Project investigation cost | 26.3 |
| Stage 2 preparatory costs | 26.1 |
| **MCA Total** | **1,138.6** |

**We are satisfied with the components of the proposed major capex allowance**

C62 Following our review, we are reasonably satisfied with the underlying calculations, cost estimates, investment timing and reports provided by Transpower, that verify Transpower's calculation of its proposed MCA.

C63 While the cost estimates for some of the proposed investment components are likely to be reasonably low risk, we consider that major cost risks concern:

C63.1 the cable asset and installation cost at $871.0 million ($ nominal); and

C63.2 the cost of the cable termination stations at $161.7 million ($ nominal).

C64 Additionally, the GHD report identified that the costs associated with the Benmore filter and Pole short-term overload scheme, while appearing to be in the right "order of magnitude", there was no strong supporting evidence to underpin the estimates.[171]

C65 We investigated how Transpower had arrived at these costs and sought additional information using an RFI.[172] We detail our capital cost estimate assessment in the following sections as we tested proposal compliance with the clause C3 requirements.

C66 A key finding of the GHD review is that there is considerable cost risk associated with this project, particularly when the control system upgrade costs are factored in. The limited manufacturer pool, commodity price and inflation changes, cable route selection and weather related issues all make cable costs highly uncertain. GHD raised questions about the control system upgrade scope and costs, and whether existing cable removal is necessary. The control system scope uncertainty and cable removal necessity meant Transpower delayed consideration of these upgrade components into a Stage 2 application.

[171] *GHD*, Independent Review - HVDC Link Upgrade Programme, Section 4.7.1 p.25, available here.
[172] Transpower response to RFI006 – Capital costs.

C67 Following our review, we consider the HVDC Stage 1 MCP project cost estimates are generally reasonable for a proposal of this nature, subject to the commissioning date of the final output by 31 December 2031.

C68 In coming to this conclusion, we are mindful that estimating the capital costs of projects in a MCP is a complex engineering process that requires:

C68.1 producing conceptual designs;

C68.2 conducting site investigations;

C68.3 scoping the projects, and then preparing the scope of work packages; and

C68.4 estimating the quantity of work for each work package.[173]

C69 In reviewing the estimated costs, we sought to form a view on whether Transpower had:

C69.1 adequately scoped the works;

C69.2 estimated the quantities;

C69.3 applied the unit costs where applicable;

C69.4 allowed for preparation costs for turnkey portions of the projects; and

C69.5 derived contingencies in a reasonable manner.

C70 We outline our approach to assessing the MCA and the analysis we carried out in the following sections.

**Our approach to evaluating the MCA**

C71 Under clause C3 of Schedule C, we must consider at least one of the following factors when evaluating the MCA:

C71.1 how Transpower used the major capex project outputs, key drivers, key assumptions, and cost modelling to determine the MCA cost (clause C3(a));

C71.2 the capital costing methodology and formulation, including unit rate sources, the method used to test the efficiency of unit rates, and the level of contingencies included (clause C3(b));

C71.3 the impact of forecast costs on other Transpower costs, including the relationship with operating expenditure (clause C3(c));

C71.4 mechanisms for controlling actual capital expenditure with respect to the MCA (clause C3(d)); and

173 Examples of work packages include site excavation, fencing, installing security lights, constructing the foundation for the equipment, strengthening tower foundations, freighting equipment onto sites and installing the MCPO's primary assets.

C71.5 the efficiency of the proposed approach to procurement of goods and services (clause C3(e)).

C72 In evaluating Transpower's proposed MCA, we considered the factors under clauses C3(a) and C3(b) because they best enable us to form a view on whether Transpower's estimated cost of the project, and the subsequent derivation of the MCA, are reasonable.

C73 To assess the capital cost of the MCP's proposed investment, Transpower provided us with:

C73.1 a costing spreadsheet that included unit costs, estimated quantities, and associated uncertainties; and

C73.2 a project costing report that outlines Transpower's approach to estimating capex, estimating the component nominal costs as well as a breakdown cost estimate of the major components of the HVDC Stage 1 MCP.[174]

C74 We assessed the estimated capital costs by:

C74.1 reviewing the above documents;

C74.2 reviewing the GHD report and using its conclusions; and

C74.3 seeking further clarification and explanation from Transpower where necessary using RFIs.[175]

C75 GHD concluded that in general there are "several elements of the cost-build up that pose potential risk" but that overall "headline cost estimates for each component appear reasonable, noting that only the cable replacement cost estimate is supported by a detailed proposal from a supplier."[176]

C76 GHD noted that there was still considerable cost risk associated with the project but that this included its consideration of the control system upgrade and removal of the existing cables. By staging the proposal, Transpower has mitigated some of the risk in this proposal stage.

## Clause C3(a) - how Transpower used the major capex project outputs to determine the MCA

C77 Transpower derived the MCA according to the project output components set out in Table C2, using the following general approach:

C77.1 determine the base estimate and uncertainties;

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174 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 5 – Costing Report, available here.

175 Transpower response to RFI006 – Capital costs.

176 *GHD*, Independent Review - HVDC Link Upgrade Programme, p.iv, available here.

C77.2 derive the P50 costs using upper and lower bound estimates;

C77.3 forecast exchange rates and inflation from 2025 to 2030; and

C77.4 forecast financing costs (interest during construction).

C78 Transpower's base estimate is the summation of the cost to deliver the five major capex project outputs, plus the support and preparedness projects (investigation and Stage 2 preparatory costs).

C79 To reach its project cost estimates, Transpower has used bespoke estimates, manufacturer quotes, external consultant reports, in-house engineering designs and its Transpower Enterprise Estimation System (**TEES**) pricing model, and indicative prices provided by potential suppliers, to estimate the cost of each works package.

C80 With regard to TEES, Transpower states:[177]

> We use Transpower's Enterprise Estimating System (**TEES**) to estimate the cost of all capex projects.
>
> TEES produces cost estimates for a project based on the historical rates from past projects or known current rates, as well as information from consultants and/or potential vendors (e.g., RFPs, concept design and solution study exercises).
>
> It also factors in changes in foreign exchange rates and costs of key commodities such as external labour, copper, steel and aluminium.

C81 Transpower notes that the MCA cost estimates it uses in the investment test are P50 estimates (there is an equal probability that actual costs will be higher or lower than the P50 estimate).

C82 Transpower also takes a probabilistic approach to calculating the project cost risk adjustment based on a probability of occurrence.

C83 We are satisfied with the probability distribution approach used by Transpower to derive the P30, P50 and P70 cost estimates. We are satisfied with the lower and upper cost estimates derived, based on estimates of material and labour unit quantities that Transpower used. The variation between these and the base quantities are in the range expected of such estimates at this phase of a project's life cycle.

C84 We tested Transpower on aspects of its cost estimation process, particularly those estimates related to the cable, cable installation and the cable termination station. We understand that there is significant time risk associated with the cable installation as this will be weather and tide dependent.

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177 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 5 – Costing Report, p.4, available here.

C85 Following our review, we are satisfied that the above methodology provides an MCA based on a P50 estimate for project costs as required by the Capex IM.[178]

## Clause C3(b) - evaluation of the base estimate using the capital costing methodology, including unit rate sources, the method used to test the efficiency of unit rates, and the level of contingencies included in the estimate

C86 We evaluated the base estimate of the MCP project cost using the technique of the capital costing methodology, and formulation as outlined under clause C3(b) of Schedule C.[179]

C87 We assessed how Transpower prepared the base estimate and whether the underlying assumptions appear reasonable.

### Our analysis of Transpower's capital costs

C88 During our review we sought specific cost and background information from Transpower to enable us to be satisfied that the costs it was proposing were supported and reasonable, including:[180]

C88.1 the costing spreadsheets showing more detail of cost elements that underpin the proposed investments;

C88.2 evidence that links TEES outputs to the proposed investments;

C88.3 explanation of the basis for Transpower's 'real escalation adjustment (over and above CPI)';

C88.4 discussion about how we can be confident that the HVDC Stage 1 projects costs are P50 estimates given the recent history of major capex project delivered costs being consistently lower than the P50 estimates;

C88.5 evidence to support the cable design costs of $43 million ($ 2025), cable overhead costs of $141.5 million ($ 2025) and cable miscellaneous costs of $22.1 million ($ 2025);

C88.6 evidence to support the cable installation risk allowance of $123.2 million ($ 2025);

C88.7 evidence to support the cable termination station cost estimate of $87.7 million ($ 2025) and whether Transpower had decided on a design and location;

178 Capex IM, clause G5(2)(c).
179 The base estimate is the cost of each element (for example labour cost, and list of material) used to provide the overall MCP project estimate.
180 Transpower response to RFI006 – Capital costs.

C88.8 evidence to support cable termination station overhead costs, design costs and risk cost estimates;

C88.9 more discussion about how the Pole 2 short-term overload scheme enables overload capability, and why this does not require a control system upgrade;

C88.10 why the Pole 2 STOL scheme risk allowance is so high (23%) when compared to other investments in the proposal; and

C88.11 evidence of the cable storage options being considered and the economic analysis used to support the proposed investment.

C89 In the following section we set our review of Transpower's additional information that have used to assist us in testing the proposal against the clause C3 requirements.

### Project delivered costs have been consistently lower than P50 estimates

C90 In our Upper South Island (**USI**) MCP draft decision, we presented analysis of recent major project costs through to delivery (see Table C2). This summary analysis showed that the project cost underspend of $114.8 million resulted in Transpower receiving significant incentive reward payments after the projects were delivered. If forecast project costs were P50 amounts, we would expect incentive rewards and penalties to balance out over time.

**Table C2 Previous major project costs through to delivery**

| Major project | Forecast cost ($m) | Expected cost ($m) | Variance in cost ($m) | Variance in cost (%) |
|---|---|---|---|---|
| Clutha Upper Waitaki Lines Project | 147.2 | 123.9 | (23.3) | (16) |
| UNI Dynamic Reactive Support | 91.4 | 57.9 | (33.5) | (37) |
| USI Grid Upgrade – Stage 1 | 6.6 | 4.5 | (2.0) | (30) |
| Waikato UNI Voltage Management | 143.1 | 106.2 | (36.9) | (26) |
| Bombay-Otahuhu | 50.5 | 31.5 | (19.0) | (38) |
| **Totals** | **438.8** | **324.0** | **(114.8)** | **(26)** |

C91 In the USI MCP draft decision, we set an incentive rate at 7.5%, because we were not convinced that Transpower's proposal cost estimates were sufficiently accurate. Additionally, Transpower's explanation of recent major project cost variances, where project delivered costs were consistently much lower than the P50 proposal estimates, was unconvincing.

C92 Transpower provided additional information about its cost estimation processes. It noted that for some of the recently delivered major projects, scope and design changes had resulted in significant cost savings.

C93 Transpower argue that that it has made significant cost estimation process improvements since 2023, namely:[181]

C93.1 the accuracy of all estimates against final delivered costs is now tracked to identify variances and to improve forecasting;

C93.2 both resourcing and processes within the cost estimation team have been strengthened since the earlier MCP estimates - this includes enhanced benchmarking, risk analysis, and supplier engagement;

C93.3 for all Transpower capex projects >$10m commissioned in RCP3, the median estimate performance was 0.84 (actual cost ÷ estimated cost at business case stage) - for projects underway but not yet completed, using forecast end costs, the median performance is 0.94. Transpower considers this demonstrates an improving trend in estimate accuracy;

C93.4 the transmission industry faces systemic risks such as resource constraints and supply chain volatility - these risks are explicitly factored into contingency and risk allowances for HVDC MCP estimates; and

C93.5 after MCP approval, the Transpower Grid Delivery team seeks opportunities to innovate and reduce costs - while these savings often result in delivered costs below approved amounts, Transpower does not assume such innovations in initial estimates due to uncertainty.

C94 Transpower conclude that "the HVDC Stage 1 MCP cost forecast reflects a mature scope and a robust estimation process, supported by historical performance data and continuous improvement measures. While systemic risks remain, these are accounted for in risk allowances, and our track record shows a trend toward greater accuracy and cost efficiency."[182]

C95 The HVDC Stage 1 MCP contains different cost risk than the USI MCP. In the USI MCP the previous incentive scheme around the P50 MCA was in force. In this MCP, the P30/P70 cost estimate deadband introduced in the 2023 Input Methodologies (**IMs**) Review applies.[183]

C96 Transpower's view is that the deadband mechanism, where the incentive reward will only apply if the project final delivered cost is less than the P30 estimate, will mitigate our incentive reward concerns. However, this proposal contains a significant P50 contingent amount, and when this is subtracted from the P50 MCA, would sit below the P30 cost estimate. This means Transpower may be rewarded for not spending a contingent amount. We discuss our treatment of the project contingency when we set the exempt major capex in Attachment D.

181 Transpower response to RFI006 – Capital costs, p.6.
182 Transpower response to RFI006 – Capital costs.
183 C*ommerce Commission*, Transpower investment topic paper, Part 4 Input Methodologies Review 2023 - Final decision, 13 December 2023, Section 3, p.41, available here.

### Cable design and installation costs

C97 Transpower provided us with additional cable cost information noting that some of this information is confidential, specifically its Capacity Reservation Agreement (**CRA**) with the cable manufacturer, Prysmian.

C98 The cable design cost of $43.1 million ($ 2025) is not a TEES estimate but has been taken from the manufacturer CRA and includes all "design-related activities required for the cable installation including surveys, studies, and both basic and detailed design by the supplier."[184]

C99 Transpower explain that the cable installation marine survey makes up 75% of the design cost specifically:[185]

C99.1 "The first phase of this survey is a detailed Remotely Operated Vehicle (**ROV**) survey of each cable to identify cable laying constraints such as rocks as small as 250mm, outcrops, reefs, steep inclines or sudden undulations in the seabed that would lead to the creation of free-spans and potential cable damage. This detailed survey information is used to micro-route the cables around those obstacles. This survey is standard international practice and occurs approximately 2 years before laying;" and

C99.2 "The second is a "pre-lay" survey which occurs 2-3 months before the cable lay. The purpose is to confirm that significant changes in highly mobile seabeds such as Cook Strait have not occurred since the detailed survey. The pre-lay survey is a Prysmian requirement to fulfil their insurance obligations."

C100 The remaining 25% of design costs include costs associated with cable crossings, cable landfall, trenching, termination bushing design and other engineering items as they arise. Transpower confirm that a direct comparison with AC cable design processes is not relevant in this case as HVDC submarine cables are complex systems with unique engineering issues.

C101 Transpower provided further information about the composition of its cable overhead costs explaining that this cost comprised a number of major components:[186]

C101.1 cable supplier project management costs: $25.2m, based on the CRA with Prysmian;

C101.2 internal project team costs: $36.2m, benchmarked against actual costs for the Pole 3 and NIGUP projects;

C101.3 professional services: $50.0m, covering engineering, design, and specialist support, also benchmarked against similar large-scale projects; and

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184 Transpower response to RFI006 – Capital costs, p.8.
185 Transpower response to RFI006 – Capital costs, p.8.
186 Transpower response to RFI006 – Capital costs, p.9.

C101.4 insurance costs: $30.1m, based on indicative figures provided by Transpower's insurer for a project of this scale and complexity.

C102 Transpower concede that while these overhead costs are high compared to other components, this is because the HVDC cable asset and installation involves "unique and complex elements not typical in standard projects – such as submarine cable installation, termination station construction, and cable storage facilities."[187]

C103 Additionally, "managing these activities requires significant supplier coordination, specialist engineering and other professional service inputs, and risk coverage (through insurance). The estimates were validated through supplier engagement and benchmarked against previous large projects to ensure accuracy and reflect the true cost of delivering a project of this magnitude."[188]

C104 Miscellaneous costs are mainly comprised of cable spares costs ($15 million - $ 2025), and market costs for testing the cable ($5 million - $ 2025).

C105 These cable asset and install costs have been sourced from the CRA with the cable manufacturer, Prysmian. Considering the cable contract has been market tested, we consider that these costs are reasonable.

C106 Transpower has also reasonably explained that the overhead and miscellaneous costs have either been benchmarked against similar large projects that it has delivered or are based on the need for spares.

### Cable risk allowance

C107 We asked Transpower to explain how it arrived at its cable asset and install risk allowance of $123.2 million ($ 2025).

C108 Transpower explain that its cable risk allowance calculation follows the American Association of Cost Engineering International (**AACEI**) recommended practices and considers both systemic risk and project specific event risk.[189]

C109 Systemic risk is assessed using a "parametric model that evaluates the level of project definition, new technology, and complexity." The parametric model inputs assumed a Class 4 level of definition – which is a low new technology, medium complexity project. The project specific risk is a quantitative risk assessment of specific bespoke project related risks. The parametric model produces a probability distribution of risk for the base cost estimate.

187 Transpower response to RFI006 – Capital costs, p.9.
188 Transpower response to RFI006 – Capital costs, p.9.
189 Transpower response to RFI006 – Capital costs, p.9.

C110 From a bottom-up specific event risk perspective Transpower identified specific cable project risks drawing from known risk due to project deliverables and their material cost impact assigning values to minimum cost impact, most likely cost impact, maximum cost impact and probability of occurrence.[190]

C111 These inputs were used to define the probability distributions for each risk event, with the following material risks modelled (those over $5 million):[191]

C111.1 vessel/equipment incident causing environmental breach and H&S investigation (Impact: $30M–$100M | Probability: 1%);

C111.2 support vessel/equipment incident causing environmental breach and H&S investigation (Impact: $10M–$30M | Probability: 1%);

C111.3 early removal of existing land cable (Impact: $3.5M–$16M | Probability: 15%);

C111.4 cable failure during testing or commissioning (Impact: $3M–$15M | Probability: 4%);

C111.5 cable vessel delay exceeding liquidated damages (Impact: $0–$10M | Probability: 15%);

C111.6 cable damage during vessel transfer (Impact: $60M | Probability: 4%);

C111.7 shipping route change due to geopolitical disruption (Impact: $10M | Probability: 58%); and

C111.8 pre-construction seismic event (Impact: $10M | Probability: 1%).

C112 From a systemic risk perspective, the variability due to factors such level of design definition, delivery complexity, market and delivery environment and technology maturity are captured and modelled.

C113 Monte Carlo simulations are then carried out using the probability distributions of systemic and event risk to "generate the overall probability distribution of the project estimate" and provide "risk allowance values for different confidence levels (P30, P50, P70) as reported in the submission."[192]

C114 Transpower has concluded, based on its modelling, that project specific event risk is $20.5 million ($ 2025) and the systemic risk of $102.7 million ($ 2025) at a P50 level of confidence.

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190 Transpower response to RFI006 – Capital costs (additional information), p.1.
191 Transpower response to RFI006 – Capital costs (additional information), pp.1-2.
192 Transpower response to RFI006 – Capital costs, p.10.

C115 We also asked Transpower about the assumptions it had made regarding cable installation costs and the key issues. Transpower has based its cable install estimate on a marine standby rate of $330,000 per day and a commissioning delay of $5 million per month. Any shipping route change may cause a $10 million additional charge and consider this is 58% likely based on the likely time of delivery.[193]

C116 Weather related additional delays may impose an additional 12 days and this is 40% likely. Other risks are identified but shipping re-routing and weather delays are the key risk drivers affecting the cable installation cost estimate.

C117 We consider Transpower has carried out an in-depth cost risk analysis and has reasonably explained how it arrived at the cable risk cost elements. We will address how we consider this risk component when we discuss the incentive scheme settings and our view of exempt major capex.

### Cable termination station costs

C118 We tested the basis for Transpower's cable termination station base costs, overhead costs, design costs and its risk cost estimate.

C119 Transpower explained that its baseline cost estimate was "based on termination station designs and locations assessed for constructability by BECA and Naylor Love." These designs represent Transpower's current preferred solution and provide a reasonable base case basis for cost estimation.[194]

C120 Transpower provided more background on its termination station overhead, design and risk cost estimates.

C121 Overhead costs are based on "guidance provided by our engineering consultant and validated through an early contractor engagement process. Because this work involves bespoke elements – such as complex civil works and integration with HVDC systems – the overhead estimate is not a standard TEES rate for new buildings. Instead, it reflects a tailored allowance for contractor overheads specific to this project's scope and complexity."[195]

C122 Design costs "were developed as part of the consultant's detailed estimate and are therefore bespoke, not based on standard TEES design cost rates for new buildings. This approach was necessary because the termination stations involve highly specialised HVDC equipment integration and unique civil and electrical design requirements that differ significantly from conventional building projects."[196]

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193 Transpower response to RFI006 – Capital costs (additional information), pp.4-5.
194 Transpower response to RFI006 – Capital costs, p.10.
195 Transpower response to RFI006 – Capital costs, p.10.
196 Transpower response to RFI006 – Capital costs, p.10.

C123 The cable termination station risk cost estimate followed the same process that Transpower followed for the cable asset and install risk cost estimate.

C124 We consider Transpower has reasonably explained how it arrived at the cable termination cost elements and why the TEES database is not relevant in this case. We will address how we consider the cable termination cost risk component when we discuss the incentive scheme settings and our view of exempt major capex.

### Pole 2 short-term overload scheme costs

C125 Transpower has confirmed that the Pole 2 STOL scheme does not require a significant control logic change. The main issue with implementing this scheme is to upgrade a number of primary assets to enable them to accept the overload when and if it occurs. Transpower has considerable experience in managing its HVDC assets and isn't reliant on manufacturers to address the primary asset issues.

C126 Despite this we sought an explanation about why the Pole 2 STOL risk cost estimate was so high (23% of total) in proportion to the total Pole 2 STOL cost estimate.

C127 Transpower explained that:

> The STOL risk allowance reflects the level of design maturity and scope certainty. The assumptions regarding the type of primary equipment required for additional cooling can only be confirmed after testing actual thermal performance has commenced under in service conditions. These tests will require reconfiguring the link and potentially coordinating with the market to maintain a constant high load.
>
> There are some different potential solutions to manage temperature rise, and our approach has been to cost the most likely option as our base estimate until further information is available. However, it is possible that the scope of this could change. Therefore, at this stage, the estimate is classified as Class 5, which carries a higher risk allowance due to inherent uncertainty.

C128 We consider that while Transpower has reasonably explained that a higher risk allowance is appropriate for this investment, there is still some uncertainty surrounding the extent of the primary asset upgrades required because it has yet to carry out primary asset thermal tests.

### Cable storage facility costs

C129 Transpower explain that it has carried out a considerable amount of investigation work to assess its storage facility options and supplied a report detailing that investigation.

C130 The investigation included "evaluations of constructability, technical feasibility, and commercial considerations for potential sites" with the "cost for the cable turntable supply and installation (which is the most significant single cost in the estimate) was based on a budgetary price by the supplier. Building quantities and associated costs were developed by our engineering consultant using their internal cost database. The remaining items in the estimate were prepared by Transpower."[197]

C131 Transpower has reasonably explained the need for a new cable storage facility and carried out an in-depth investigation to locate and price that new facility (although this has yet to be finalised). We consider that Transpower has reasonably estimated costs for this aspect of the proposal.

### The use of TEES

C132 Ordinarily Transpower is reliant on its TEES cost database to estimate project capital and maintenance costs for projects and in previous major capex proposals we have reviewed the TEES database outputs and unit rates.

C133 Most of the project cost estimates in this proposal are not reliant on the TEES cost process and are bespoke in nature. HVDC assets are unique and HVDC projects of this magnitude are not business as usual projects.

### Summary

C134 We have evaluated Transpower's proposed MCA and considered the factors under clauses C3(a) and C3(b). Following our review of the proposal, the GHD report and additional information supplied to us by Transpower, we consider that the estimated cost of the project, and the subsequent derivation of the MCA, which includes risk cost elements, are reasonable and consistent with the requirements of the Capex IM.

### Base estimate contingency

C135 The two types of risk contributing to major project base estimate cost uncertainties are:

- C135.1 scope risk, which arises from estimating accurate quantities for work packages; and
- C135.2 project risks, which arise from variations in prices, stakeholder liaison, environmental considerations, project commencement timing, and project duration due to external events, such as weather.

C136 We considered whether we should agree with the contingency amount Transpower had proposed in this MCP following our major project cost variance analysis, and decided that:

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197 Transpower response to RFI006 – Capital costs, pp.11-12.

C136.1 it is reasonable to expect that major projects should have contingency amounts added to address reasonable project and scope risks; and

C136.2 the best way for us to address the risk that project scope designs are too preliminary, and/or there is capital cost over-estimation, is to set a lower incentive rate.

C137 For these reasons, while we are not fully convinced that Transpower's MCP cost estimation is fit for purpose (because project scoping may not being sufficiently advanced or additional contingencies are being added), we acknowledge that the uncertainties discussed and proposed by Transpower, are likely to be consistent with clause G5(2)(c) of Schedule G of the Capex IM based on the information we have reviewed.[198]

C138 In the proposal, Transpower has expressed contingencies on a per project output basis in the costing report (see Table C3). We reviewed the contingency amounts for the key project outputs and their relationship to the base cost estimate amount.

**Table C3 HVDC Stage 1 project base cost estimates and contingency amounts ($m 2025)[199]**

| Project output | Base estimate | Contingency | Contingency % of base estimate |
|---|---|---|---|
| Supply and install of cables | 760.4 | 123.2 | 16.2% |
| Cable termination station replacement | 134.5 | 10.2 | 7.6% |
| Benmore filter bank | 19.7 | 2.4 | 12.2% |
| Pole 2 short-term overload scheme | 12.7 | 2.9 | 22.8% |
| New cable storage facility | 11.6 | 1.4 | 12.1% |

C139 The level of contingency proposed by Transpower range from 7.6% to 22.8% depending on the project output (project average of 14.3% when investigation costs of $19.5 million and Stage 2 preparatory costs of $19.6 million are included in the total).

C140 The total project contingent amount, in percentage terms, is significantly higher than previous major capex projects, namely:

C140.1 Net Zero Grid Projects (**NZGP**) Stage 1 MCP (10.8%);

C140.2 Western Bay of Plenty (**WBOP**) MCP (11.5%);

C140.3 Redclyffe (**RDF**) substation resilience MCP (8.9%); and

198 This requires the proposed MCA be a P50 estimate of the capital cost, and the estimated probability distribution of the P50.

199 Transpower response to RFI011 – P50 cost estimates.

C140.4 USI MCP (9.1%).

C141 Our view is that these contingent amounts are appropriate for the type of projects in this proposal. As noted previously, there is significant uncertainty surrounding this project, particularly in the cable capital costs and installation costs which will be weather and tide dependent. There is a reasonable chance that the contingent amounts will need to be incurred so have been included in the MCA we approve.

**Exchange rate and inflation assumptions**

C142 The MCA exchange rate and inflation assumptions are subject to the wash-up mechanism, which means these assumptions do not impact the incentive calculation or the final revenue amount Transpower can recover.[200]

C143 In a base capex proposal we expect reasonable estimates of exchange rate and inflation. When actual values are used in the revenue wash-up they are adjusted against the base capex proposal best estimates, so that the revenue impact of the change is minimised.

C144 For this listed project application, Transpower's exchange rates and inflation assumptions are shown in Tables C4 and C5 below.

**Table C4 Exchange rates used to calculate the MCA[201]**

| Currency | Exchange rate |
|---|---|
| AUD | 0.9148 |
| EUR | 0.5064 |
| SEK | 6.0129 |

**Table C5 Forecast inflation rate used to calculate the MCA[202]**

| Year | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2030 | 2032 |
|---|---|---|---|---|---|---|---|---|
| **Rate** | 2.6% | 2.0% | 2.1% | 2.0% | 2.0% | 2.0% | 2.0% | 2.0% |

C145 We consider that the exchange rate and inflation assumptions Transpower has made are reasonable and largely consistent with recent MCP applications and the RCP4 IPP proposal.

200 Capex IM, clause B3(1) of Schedule B.
201 Transpower response to RFI010 – Exchange rate, inflation and financing costs.
202 Transpower response to RFI010 – Exchange rate and financing costs, p.3.

**Financing cost assumptions**

C146 Transpower has estimated its financing costs based on the assumptions that:[203]

C146.1 the financing rate is set at Transpower's cost of debt (not the current weighted average cost of capital (**WACC**));[204,205]

C146.2 financing costs are calculated for the MCA on a quarterly basis; and

C146.3 the same principles used in its RCP4 base capex proposal continue to apply.[206]

C147 The capital expenditure profile of the HVDC Stage 1 MCP is aligned with capital expenditure profiles for other recent major capex projects.

C148 Transpower explains that "Most of our expenditures occur during the construction phase, while earlier spending covers procurement of long lead time materials and specialist manufacturing and delivery services due to limited market capacity. Initial costs also include securing resource consents and planning approvals, detailed design services and project mobilisation. Project delays are incorporated in our cost estimate under the risk allowance".[207]

C149 We consider that the financing cost assumptions Transpower has made are reasonable.

## Clause C4 – evaluation of the proposed approval expiry date

C150 Transpower proposes an approval expiry date of 31 December 2036 for the HVDC Stage 1 MCP.

C151 The effect of an approval expiry date is that Transpower cannot recover the costs of any assets commissioned after this date. This incentivises Transpower to deliver the MCP project within the approval expiry date or apply for an amendment to that date under clause 3.3.6(1)(d) of the Capex IM.

C152 In evaluating Transpower's proposed approval expiry date under clause C4 of Schedule C of the Capex IM, we must have regard to at least one of the six factors listed in that provision.[208]

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203 Transpower response to RFI010 – Exchange rate and financing costs, p.3.

204 We set the WACC in our cost of capital determination: *Commerce Commission*, Cost of capital determination for electricity distribution businesses' 2020-2025 default price-quality paths and Transpower New Zealand Limited's 2020-2025 individual price-quality path (2019) NZCC 12 (25 September 2019), available here.

205 Costs and benefits for the Investment Test are discounted at standard discount rates set out in the Capex IM. For the USI MCP a 5% discount rate was used, with sensitivities at 3% and 7%.

206 Under clause 1.1.5(2) of the Capex IM, the 'base capex proposal' is the information Transpower submits to enable us to determine the components of the IPP under clause 2.2.2 of the Capex IM.

207 Transpower response to RFI010 – Exchange rate and financing costs, p.3.

208 Capex IM, clause C4.

C153 We tested Transpower's proposed approval expiry date against the factors set out in clause C4(c): the effect of the proposed approval expiry date, and the commissioning date assumption in the HVDC Stage 1 MCP.

C154 We agree that Transpower's approval expiry date is reasonable since it provides Transpower with sufficient time to deliver on the HVDC Stage 1 MCP, while managing the short-term uncertainties. Our draft decision is that the clause C4 requirements have been met.

## Clause C5 – evaluation of the major capex project outputs

C155 We evaluated Transpower's proposed major capex project outputs against the factors set out in clause C5(a): the extent to which the major capex project outputs reflect the nature, quantum, and functional capability of the transmission investment assets to be commissioned.

C156 The nature and functional capability of the proposed transmission investments are to replace existing assets and to enhance HVDC transmission capacity. The replacement capex component of this MCP is driven by HVDC cable end-of-life considerations and a prediction that HVDC cable asset failures will be more likely in the future.

C157 The HVDC capacity enhancement component of this MCP is to allow cheaper renewables generation, forecast to locate in the South Island, to access the electricity market in the North Island. Other HVDC capacity investments are being made to improve the functionality of the HVDC link such as the Pole 2 short-term overload function which will reduce electricity market reserve requirements in anticipation of a pole outage.

C158 We are satisfied the HVDC Stage 1 MCP outputs reflect the nature, quantum, and functional capability of the transmission investment assets to be commissioned. Our draft decision is that the requirements of clause C5(a) have been met.

## Clause C6 – evaluation of the major capex incentive rate and exempt major capex

C159 The major capex incentive rate we set under clause 3.3.5(7)(b) of the Capex IM determines the reward (or penalty) that Transpower receives (or bears), depending on how the actual cost of delivering a major capex project compares to the project's MCA.[209] Exempt major capex is that portion of the MCA amount to which the major capex incentive rate does not apply to.[210]

C160 Transpower has proposed:[211]

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209 Capex IM, clause B3(1) of Schedule B determines how the major capex incentive rate applies to an approved major capex project.

210 Capex IM, clause 1.1.5(2).

211 *Transpower NZ Ltd*, HVDC Stage 1 MCP Main Overview, Table 1, p.5, available here.

C160.1 a major capex incentive rate of 15%; and

C160.2 that we do not set any exempt major capex.

C161 We discuss Transpower incentive rate and exempt major capex proposals below.

**Major capex incentive rate**

C162 Under clause 1.1.5(2) of the Capex IM, the major capex incentive rate is 15%, the default rate, or an alternative rate we may specify. In its HVDC Stage 1 MCP proposal, Transpower has proposed that the default MCP incentive rate of 15% apply.[212]

C163 For the reasons discussed in paragraphs C86 to C136, we have set the incentive rate in the HVDC Stage 1 MCP to 15%.

**Exempt major capex**

C164 Exempt major capex is typically set for portions of the MCA that reflect uncertainties that are outside the control of Transpower. Transpower has proposed that we do not set any exempt major capex.

C165 We recently consulted on amending the incentive rate formula for major capex applications and have applied those proposed amendments to this draft decision.

C166 In the 2023 IM Review, we introduced a project cost deadband mechanism where Transpower would not be subject to an incentive penalty/reward if an MCP's delivered project costs are within the project's P30 and P70 cost estimates.[213]

C167 The deadband was introduced in addition to the existing mechanism requiring us to set an amount of exempt major capex. For previous approved MCPs we have typically set the exempt major capex in reference to the portions of the MCA that reflect uncertainties.

C168 In addition to the P30/P70 cost estimate deadband, we retained the exempt major capex mechanism if we considered Transpower cost estimates contained excessive contingency and a different reward trigger needed to be set below the P30 cost estimate.

C169 Transpower has characterised the HVDC Stage 1 project cost estimate contingency as a risk adjustment to "account for cost uncertainty not represented in our lower and upper bound estimates."[214]

212 *Transpower NZ Ltd*, HVDC Stage 1 MCP Main Overview, Table 1, p.5, available here.
213 *Commerce Commission*, Transpower investment topic paper, Part 4 Input Methodologies Review 2023 - Final decision, 13 December 2023, Section 3, p.41, available here.
214 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 5 – Costing Report, p.4, available here.

C170 In the proposal Transpower has proposed that we do not set any exempt major capex. In previous MCP decisions we have set exempt major capex amounts that are linked to the project cost contingency amounts. Our reasoning was that Transpower should not be rewarded through incentives for saving cost contingency amounts or penalised for spending them.

C171 In this MCP, the project cost contingent amounts with reference to the P50 total project cost estimate are:[215]

C171.1 $123.2 million ($ 2025) for the supply and installation of four new HVDC submarine cables;

C171.2 $10.2 million ($ 2025) for the cable termination station replacement;

C171.3 $2.4 million ($ 2025) for the Benmore filter bank;

C171.4 $2.9 million ($ 2025) for the Pole 2 overload scheme; and

C171.5 $1.4 million ($ 2025) for the cable storage facility.

C172 The total project cost contingent amount is $140.1 million ($ 2025) which is 14.3% of the total P50 project cost estimate of $978.1 million ($ 2025).

C173 As noted previously, this contingent amount in percentage terms is significantly higher than previous major capex projects, namely:

C173.1 NZGP Stage 1 MCP – 10.8%;

C173.2 WBOP MCP – 11.5%;

C173.3 RDF substation resilience MCP – 8.9%; and

C173.4 USI MCP – 9.1%.

C174 The high percentage contingent amount is mainly due to the cable installation risk component of $123.2 million ($ 2025). This risk component is high due to route selection uncertainty, and weather related issues may impact cable laying in Cook Strait.[216]

C175 In line with previous MCPs, we consider that the HVDC Stage 1 MCP proposal cost contingent amount should be exempt major capex and that Transpower should not be rewarded for not spending a contingent amount.

C176 Additionally, we consider project cost risks have a reasonable possibility of materialising and have therefore included them in the MCA. This allows Transpower to recover those costs should the risks materialise.

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215 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 5 – Costing Report, Tables 3-4, pp.5-7, available here.

216 Transpower response to RFI006 – Capital costs.

C177 This approach is consistent with how we treat uncertainties relating to foreign exchange, and inflation forecast error as mentioned under 'Exchange rate and inflation assumptions'.

C178 Our draft decision, under clause 3.3.5(7)(c) of the Capex IM, is to treat the project cost risk component of the MCA as exempt major capex, equal to $171.2 million in $ nominal prices.[217]

C179 This means the capital cost uncertainties between the P70 cost estimate of $1,262.7 million ($ nominal) and the reward trigger setting at the P50 MCA minus the exempt major capex at $967.4 million ($ nominal), will not be subject to the incentive mechanism.[218] The incentive reward trigger is now set below the P30 MCA cost estimate of $1,049.6 million ($ nominal).

C180 Accordingly, in setting the exempt major capex and the major capex incentive rate, the incentive scheme under clause B3(1) of Schedule B of the Capex IM will work as follows. If the actual cost of delivering the HVDC Stage 1 MCP is:

C180.1 less than the P50 MCA minus exempt major capex and less than the P30 cost estimate, then applying the major capex incentive rate, Transpower will be rewarded;

C180.2 between the P50 MCA minus exempt major capex and the P70 cost estimate there is no reward or penalty; and

C180.3 more than the P70 cost estimate, then applying the major capex incentive rate, Transpower will be penalised

217 Transpower response to RFI014 - Risk component in nominal terms.

218 *Transpower New Zealand Ltd*, HVDC Stage 1 MCP Attachment 5 - Costing, Table 13, p.15, available here.

# Attachment D Evaluation of the investment test

## Purpose of this attachment

D1 In this attachment we set out our review of Transpower's application of the investment test to the HVDC Stage 1 MCP.

D2 We discuss our evaluation of:

- D2.1 the parameters Transpower used for the investment test;
- D2.2 the expected net electricity market benefits Transpower found;
- D2.3 Transpower's selection of the proposed investment;
- D2.4 our assessment of Transpower's investment test application; and
- D2.5 the results of Transpower's sensitivity analysis.

### Criteria for satisfying the investment test

D3 The investment test set out in Schedule D of the Capex IM requires Transpower to use a cost benefit analysis, using discounting of relevant costs and benefits in the electricity market over a defined calculation period, to identify the most economic investment option as the proposed investment.[219]

D4 Under clause D1(1) of Schedule D, a proposed investment satisfies the investment test if it has the highest expected net electricity market benefit and is robust to sensitivity analysis, compared with other investment options.

D5 The net expected electricity market benefit:[220]

- D5.1 does not need to be positive for the proposed investment to meet the N-1 criterion of the Grid Reliability Standards (**GRS**); but
- D5.2 needs to be positive for any other proposed investment.

D6 When selecting the proposed investment, Transpower may consider unquantified electricity market benefits or cost elements, if the difference in expected net electricity market benefits between two or more investment options, is within 10% of the aggregate project costs.[221]

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219 2012 Capex IM Reasons paper at para 7.2.1. We note that in our 2017/18 Capex IM review, we decided to retain the investment test criteria and approach in the 2012 Capex IM. See 2017/18 Capex IM review reasons paper at para 194.

220 Capex IM, clause D1(1)(b).

221 Capex IM, clauses D1(1)(c)(ii) and D1(2).

## We are satisfied with Transpower's application of the investment test

D7 Under clause C1(1) of Schedule C of the Capex IM, we are satisfied:

D7.1 with the parameters Transpower used in applying the investment test;

D7.2 that Transpower's proposed investment satisfies the investment test; and

D7.3 that Transpower's proposed investment is robust to sensitivity analysis.

## How the investment test is performed

D8 In carrying out the investment test, Transpower must:[222]

D8.1 estimate the electricity market benefits, or cost elements and project costs, for each investment option under each relevant generation and demand scenario;[223]

D8.2 calculate the net electricity market benefits for each investment option under each relevant generation and demand scenario. The net electricity market benefit is the sum of the electricity market benefits, less the sum of the electricity market costs, including the project cost; and

D8.3 calculate the expected net electricity market benefit, which is the weighted average of the net electricity market benefit, under each relevant demand and generation scenario.

D9 As part of carrying out the investment test, Transpower must also test whether its proposed investment is sufficiently robust under sensitivity analysis, which verifies whether the proposed investment is robust to changes in some of the key assumptions.[224]

## How we evaluated Transpower's application of the investment test

D10 In this MCP Transpower is proposing to invest to replace existing HVDC assets and to enhance HVDC capacity.

D11 Under the Capex IM, we reviewed Transpower's application of the investment test by considering whether:

D11.1 the replacement component of the proposed investment is in relation to asset replacement and refurbishment capex, and is work that:[225]

D11.1.1 is primarily driven by Transpower's policies for replacing conductors or cables on a transmission line;

222 Capex IM, clause D2.

223 The terms 'electricity market benefit or cost element', 'project cost', and 'relevant generation and demand scenarios' are defined in clause D4(1), (2), and clause D3(4) of Schedule D.

224 Capex IM, clause D1(1)(a).

225 Capex IM, clause 2.2.2(8)(b).

D11.1.2 improves the original service potential of the transmission line; and

D11.1.3 is required due to the condition or performance of the conductors or cables.

D11.2 the capacity enhancement component of the proposed investment meets the economic criterion of the GRS and provides a positive net market benefit;

D11.3 the investment need date is reasonable;

D11.4 the parameters of the investment test are appropriate and whether Transpower consulted on the parameters it applied;

D11.5 Transpower has reasonably estimated the expected net electricity market benefit of each investment option considered;

D11.6 the proposed investment is the investment option with the highest net electricity market benefit; and

D11.7 the proposed investment is robust to sensitivity analysis.

D12 We present a summary of our evaluation of Transpower's investment test application in the rest of this attachment.

## The proposed capacity enhancement investment needs to meet the economic criterion of the GRS

D13 Transpower has submitted the MCP to meet clause D1(1)(b) of Schedule D of the Capex IM.

D14 Following our review of the proposal, we agree that Transpower's proposed investment and the alternative investment options it considered, are consistent with investments required to meet the economic criterion of the GRS.

D15 Transpower states in its proposal that the proposed investment also provides the highest expected net electricity market benefit.[226]

D16 Following our review, we are satisfied Transpower has demonstrated that its proposed investment provides the highest expected net electricity market benefit when compared to the alternatives it considered.

D17 We also tested whether the capacity enhancement component capex would be economically justified if proposed as a separate MCP proposal. We are satisfied that this is the case.

[226] *Transpower NZ Ltd*, HVDC Stage 1 MCP Main overview, Table 4, p.20, available here.

D18 If there was no HVDC capacity upgrade proposed by Transpower then this MCP would be a listed project. A listed project is concerned with capex that is asset replacement and refurbishment capex (essentially like-for-like asset replacements).

D19 The majority of the proposed capex in the proposal is to replace existing assets (the three HVDC cables) and the associated works that need to be upgraded due to earthquake related issues (the cable termination station) and assets that are no longer fit for purpose and cannot be accessed when needed (the spare cable storage facility).

D20 Despite Transpower demonstrating that the total investment package has passed the investment test and provides the most positive electricity market benefit, we need to test if the investment components that would have comprised a listed project application are reasonable investment to make and that the investment need to replace them has been demonstrated.

D21 In the following sections we set out our analysis of the investment need for these investments.

**Investment need - Cable replacement**

D22 Transpower has explained in its proposal that the existing HVDC cables will need replacement. It states that the expected life expectancy of the cables is approximately 40 years and that given these were installed in 1992, they are reaching end-of-life.

D23 As the cables are approaching end-of-life, Transpower has been developing cable asset health models and has increased its condition assessments stating that:[227]

D23.1 the asset health model design is informed by a failure mode and effects analysis (**FMEA**);

D23.2 the FMEA model calculates and forecasts asset health using an expected life of 50 years combined with location factors, duty factors and observed and measured condition;

D23.3 the condition modelling includes cable exposure to current flow in the Cook Strait, seabed composition, cable depth and cable support (free-spans) and the number of voltage polarity reversals. The observed condition is obtained through regular Remotely Operated Vehicle (**ROV**) and Scuba inspections. Measured condition is obtained through annual electrical testing, specifically Line Impedance Resonance Analysis (**LIRA**)

D24 Transpower notes that cable condition varies along the line and the asset health models splits the cable into 1km lengths to reflect different external exposures. Transpower has forecast that the first year for replacement intervention is in 2032 for cables 4 and 5, and 2035 for cable 6.

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227 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 3 – Cable Condition Assessment Report, available here.

D25 We tested the Transpower asset health modelling process and outcomes as well as assessing the GHD Independent Report. GHD concluded that:[228]

D25.1 the cable health model is based on an internationally recognised framework Common Network Asset Indices Methodology that tracks cable condition and ageing indicators across the full length of the cables;

D25.2 the condition assessment follows good electricity industry practice (**GEIP**) to determine the condition of the cables;

D25.3 the submarine cable failure rates are considered to follow prudent asset management practice. International projects such as Konti-Skan 1 and 2 (Sweden to Denmark) are following a similar plan to Transpower to replace their circa 1988 HVDC submarine cables; and

D25.4 the cable Asset Health Index (**AHI**) modelling indicates a trend towards an earlier predicted year for cable intervention with each update of the model. The trend towards earlier replacement has been primarily influenced by discovery of additional defects and changes to the seabed, combined with increasing cable age. The AHI trends show that even if the poorer sections were replaced first, the next poorest sections would need to be replaced between 2032 and 2037.

D26 We asked Transpower for further clarifying information in an RFI.[229] We sought more detail about how Transpower had identified the replacement need date.

D27 Transpower responded that:[230]

D27.1 while the modelling does not predict an exact year of failure, the probability of failure has been increasing as it updates its condition assessments.

D27.2 predicting end-of-life (**EoL**) is challenging because environmental factors can vary year to year or even event to event. Each year only about one-third of the cable is inspected via ROV and scuba surveys, and coverage can be reduced further by adverse conditions (rough seas or high winds);

D27.3 external factors beyond Transpower's control also influence the cables condition, given the open sea environment;

D27.4 consistent with our approach with other assets, an asset health score of 8 serves as an indication only; at higher scores, the probability of failure rises significantly and accelerates with further degradation; and

D27.5 Cable 4 shows its earliest section reaching a score of 8 in 2032, with six sections requiring intervention by 2038. Overall cable health is determined by

228 *GHD*, Independent Review - HVDC Link Upgrade Programme, Section 5.1.2, pp.30-31, available here.

229 Transpower response to RFI001 – HVDC cable replacement.

230 Transpower response to RFI001 – HVDC cable replacement.

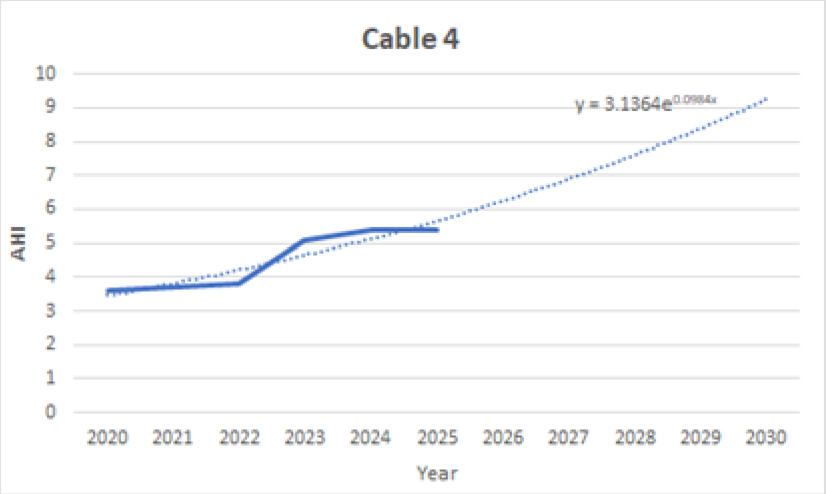
the weakest section, as failure of a single section compromises the entire cable.

D28 We carried out our own modelling of Transpower's asset health indicator analysis presented in its cable condition report. Consistent with Transpower internal policy of planning to replace key assets with an AHI of 8 or above, Transpower appears to have proposed reasonable estimates of the cable replacement dates.

D29 Our analysis projected forward the asset health indicator data presented in Transpower's cable condition assessment report to test whether an AHI of 8 or above corresponded to the Transpower replacement need dates.

D30 Figure D.1 presents AHI results for cable 4 and shows that an AHI of 8 is likely to occur around 2030, a trigger for cable replacement, and confirmation of the Transpower replacement decision.

**Figure D1 AHI estimates for HVDC cable 4**




D31 While the decision to replace the cables by the early 2030s is a model-driven risk-based decision, Transpower notes that it has already had to repair a cable fault in 2004. A ground fault was detected 345m from the cable sealing end at Oteranga Bay and repaired. Even though the fault occurred close to the Oteranga Bay termination, it still took 6 months before the repair was completed.

D32 Transpower notes in its application that not all cable fault repairs will be the same and, in some instances, may not be possible due to fault location.

D33 In summary, we consider that Transpower has made the case for the replacement of the existing cables and that the need date has been demonstrated. This technical decision to replace the cables is bolstered by the conclusions of the GHD expert review.

**Investment need – Cable termination stations**

D34 The cable termination stations "enclose the cable terminations at each end of the submarine cables. These buildings require upgrades to meet modern engineering and seismic requirements as well as modifications to accommodate the new termination requirements of the replacement cables."[231]

D35 The cable termination station buildings also house "critical systems to protect the cable terminations and maintain a clean, controlled environment for sensitive components. These buildings are positively pressurised to prevent dust or salt ingress."[232]

D36 The termination station buildings were originally built in 1965 and Transpower identify these need to be upgraded to meet modern earthquake standards. Transpower state in its proposal that the buildings are classified as Importance Level 4 (**IL4**) structures due to their role in maintaining inter-island electricity transfer. [233]

D37 Transpower structural design standards are aligned with New Zealand Standard **NZS 1170.0 Structural design actions – General principles**, where category IL4 structures are "Buildings or facilities that must be operational immediately after a major disaster or whose failure would lead to significant loss of life, disruption to critical services, or significant economic or environmental consequences."[234] Transpower design principles assign the IL4 threshold to major electricity substations, control centres, and other key infrastructure like the HVDC link.

D38 Transpower's seismic assessment concluded that the current seismic capacity of the cable termination buildings is 34%, which significantly below the 75% new building standard requirement for category IL4 structures.

D39 Transpower carried out independent study that considered both rebuild and new build options for the termination station structures. This study set out:

> the key challenges with existing sites and considers engineering solutions to overcome those challenges. It also provided examples of new build stations that could overcome the challenges. It concluded that seismic strengthening would involve extensive work to the floors, walls, roof, and foundations, requiring prolonged outages. Critically, due to safety risks, this work cannot be performed above or around live HVDC equipment. It is estimated that to do this work would require a 6-12 month outage of both HVDC poles.

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[231] *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 2 – Need, demand and generation scenarios, Section 1.3, p.5, available here.

[232] *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 2 – Need, demand and generation scenarios, Section 1.3.3, p.9, available here.

[233] *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 2 – Need, demand and generation scenarios, Section 1.3.3, p.10, available here.

[234] *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 2 – Need, demand and generation scenarios, Section 1.3.3, p.10, available here.

D40 Additionally, the existing buildings are only configured to accommodate three cables and an additional cable would require building modifications.

D41 Given these factors, Transpower concluded that the most practical and economic solution was to fully replace the termination station buildings adjacent to the existing building. Transpower note that this option has multiple advantages including that:

D41.1 construction and connection of the new cables can occur without interrupting operation of the HVDC link;

D41.2 HVDC link outages during commissioning are minimised; and

D41.3 safety is enhanced by avoiding work in live environments.

D42 In its review, GHD concluded that the cable termination station upgrade options considered were consistent with good industry practice and noted that:[235]

> The design demonstrates the early consideration emerging information on seismicity in the use of SSSHA (site specific seismic hazard assessment) to determine seismic design criteria and the presence of the Geotechnical Investigation & interpretive report. Both have been incorporated into in the presented concept designs.56 The documentation demonstrates that the steps taken in concept design to test technical feasibility are satisfactory.

D43 GHD agreed with Transpower that the building upgrade option was not feasible due to the extended HVDC link outage required for the works to be completed safely. The economic cost of this would be substantial.

D44 Following our review, we agree with Transpower's conclusion that new buildings are the most appropriate option. However, we have some reservations about the final costs as Transpower has yet to fully decide on a new building site for the Oteranga Bay termination. We discuss this more fully in our capital cost review.

**Investment need – Cable storage facility**

D45 As part of the cable replacement contract, Transpower is purchasing 10km of spare cable to enable it to effect repairs if required. For this a dedicated cable storage facility is necessary.

D46 Transpower has concluded that the existing cable storage site at Miramar is no longer fit for purpose because it requires the use of the Miramar wharf, which was closed in 2015. There are no plans to replace or repair this wharf, and the new airport flight path restrictions will limit the height of the repair vessel when it loads the spare cable. For these reasons the investment need has been demonstrated and is considered reasonable.

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235 *GHD*, Independent Review - HVDC Link Upgrade Programme, Section 5.2, pp.32-34, available here.

D47 Transpower has proposed a new cable storage facility but has yet to finalise the location. In response to RFI005 Transpower provided a consulting report that explored and tested a number of suitable options.

**Investment need for replacement of existing assets – Summary**

D48 Following our review, we consider that Transpower has reasonably demonstrated the need for the replacement of the existing three HVDC cables, new cable termination stations and a new cable storage facility.

## Our evaluation of the parameters and assumptions of the investment test application

D49 The Capex IM allows Transpower some discretion to select the analysis parameters of the inputs into the investment test. Transpower is required to consult on the values of the parameters it uses.[236] The key parameters in this proposal are the:

D49.1 calculation period;[237]

D49.2 discount rate;[238]

D49.3 demand and generation scenarios (comprising demand forecasts and generation scenarios);[239] and

D49.4 investment options Transpower considered and consulted on.[240]

D50 For the reasons we outline below, we are satisfied that Transpower has reasonably selected the investment test parameters.

**Calculation period**

D51 In its calculation of costs and benefits, Transpower states "we propose using a 30-year period from the commissioning date of the proposed Stage 1 investment (2031 to 2060)."[241]

D52 The default calculation period, under clause G5(11)(b) of Schedule G of the Capex IM, is 20 years.

D53 Transpower argues that the 30-year calculation period is justified because:[242]

[236] Capex IM, clause I4.
[237] Capex IM, clause G4(5)(b).
[238] Capex IM, clause G4(5).
[239] Capex IM, clause G3(1).
[240] Capex IM, clause 7.4.1(2).
[241] *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 7 – Investment test, Section 2.2, p. 6, available here.
[242] *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 7 – Investment test, Section 2.2, p. 6, available here.

D53.1 the "submarine cables have an expected installed life of 40 years" and "using a calculation period to 2060 covers three-quarters of the submarine cables' assumed 40-year life";

D53.2 to "ensure fair comparison across options, we have calculated the Equivalent Annualised Cost (**EAC**) over the full lifetime of the asset (i.e., 40 years for submarine cables). This involves applying an annuity factor to the present value of the investment costs. Additionally, annualised costs are truncated at 2060 to align with the modelled benefits."

D54 Transpower's view is that a 30-year calculation period "along with the inclusion of EAC, to be an appropriate balance between capturing the long-term benefits of investment and managing the uncertainty of distant future benefits."

D55 Transpower proposed using a 30-year calculation period in its short-list consultation material and no submitters raised an objection.

D56 We are satisfied the calculation period Transpower has selected, and the timeframe over which it has calculated the costs and benefits in the application of the investment test, are reasonable and appropriate.

**Discount rate**

D57 In its application of the investment test, Transpower has used a discount rate of 5% and sensitivities of 3% and 7%.[243] Transpower consulted on its proposed use of the amended discount rate and is consistent with changes made to the Capex IM, which took effect from 1 April 2025.

D58 The effect of a lower discount rate is that the long-term benefits of transmission investment will be higher on a net present value (**NPV**) basis, in a cost benefit analysis.

**Demand and generation scenario use in the investment test**

D59 The Capex IM requires Transpower to use the relevant demand and generation scenarios when it calculates the expected net electricity market costs and benefits in the investment test.[244]

D60 The relevant scenarios that Transpower use must be either the demand and generation forecasts published by the Ministry of Business, Innovation and Employment (**MBIE**), or Transpower's development of a reasonable variation of those scenarios (scenario variations), having had regard to the views of interested persons on the variation.[245]

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243 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 7 – Investment test, Section 2.3, p. 6, available here.

244 Capex IM, clause D2(1).

245 Capex IM, clauses D3(1) and D3(2). Under clause I1(1)(b), Transpower must consult on each demand and generation scenario variation.

D61 The most recent scenarios published by MBIE are the 2024 Electricity Demand and Generation Scenarios (**EDGS**), published in July 2024.[246]

D62 In its proposal, Transpower states that:[247]

> For this MCP we have based our analysis on the 2019 EDGS with several updates and variations. We updated the 2019 EDGS to reflect consultation we undertook as part of the Net Zero Grid Pathways 1 (**NZGP1**) workstream in 2021 (which we refer to as the NZGP1 EDGS Variations).

D63 In this MCP, the scenario assumptions are important, particularly the generation assumptions, as these have a significant bearing on the quantified benefits that drive the proposed capacity upgrade of the HVDC to 1400 MW.

D64 As such, we focussed a lot of our review on Transpower's generation scenario assumptions and sought additional information where we considered Transpower had not adequately addressed short-list submitter points.

D65 In the following sections, we discuss Transpower's use of the 2019 EDGS and updates to this, consider feedback from short-list submitters, and set out our own analysis following the RFI process.

**Generation scenarios in the HVDC Stage 1 MCP**

D66 A generation scenario is a hypothetical prediction of a set of generation developments within the electricity industry and is used by Transpower to calculate the fuel cost differences between generation developments, market dispatch costs and to calculate network losses.

D67 When calculating costs and benefits in the Capex IM, generation scenario assumptions are used to quantify whether upgrades in the transmission network to facilitate the connection of new generation and HVDC capacity upgrades are economic.

D68 This HVDC Stage 1 MCP is an upgrade to meet the economic limb of the GRS – the benefits of the upgrade need to outweigh the costs. As such, the generation scenario assumptions will have a significant economic impact.

**Generation scenarios – 2019 EDGS vs 2024 EDGS**

D69 In its short-list consultation, Transpower received feedback from Meridian that its proposed use of an update to the 2019 EDGS was out of date because it contains some unrealistic assumptions, specifically:[248]

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[246] https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-modelling/electricity-demand-and-generation-scenarios

[247] *Transpower NZ Ltd*, hvdc Stage 1 MCP Attachment 2 – Need, demand and generation scenarios, Section 2, p.13, available here.

[248] *Meridian*, HVDC Stage 1 MCP short-list consultation submission, p.2, available here.

D69.1 the availability of North Island gas to support thermal generation investments in the North Island; and

D69.2 low rates of solar uptake.

D70 We sought additional information from Transpower about the points raised by Meridian and the use of the 2019 EDGS. Transpower responded stating that:[249]

D70.1 the outlook for natural gas has changed significantly in recent years and although gas supply is not restricted in our model, our scenarios are consistent with reductions in future gas supply - for example, we assume the closure of the baseload gas generation plants TCC and Huntly E3P in 2026 and 2037 respectively;

D70.2 the total amounts of gas generation reduce considerably over the study horizon, from approximately 6 TWh in 2025 to 0.5 TWh by 2040; and

D70.3 our market modelling suggests that an earlier gas exit or higher gas costs would increase the relative benefits of transmission options that enable renewable generation and strengthen the benefits of 1400 MW capacity HVDC.

D71 Transpower conclude that in "assuming ongoing gas availability our analysis takes a conservative approach to the benefit quantification".

D72 Following the recent government Liquid Natural Gas (**LNG**) terminal announcement, we asked Transpower to discuss the impact of this decision its peaking generation assumptions and the economics of enhancing HVDC capacity to 1400 MW. Transpower responded that:[250]

D72.1 the benefits modelling for the proposal has assumed "an unrestricted supply of natural gas" and "does not reflect the constraints on gas supply which have been observed in the gas market in the recent years, or those which may exist in the future";

D72.2 the economic analysis set "the cost of gas supply to the price of imported LNG, assuming that either LNG was available, or domestic production priced to this point". Consequently, the benefits modelling is consistent with future LNG supply, with a supply cost assumption of $19/GJ "within the range of the Government's recent estimates ($17/GJ - $22/GJ)"; and

D72.3 "more expensive thermal fuel can be expected to increase the benefits of capacity enhancements on the HVDC", as it allows "South Island hydro generation to displace thermal generation". If LNG prices turn out to be "higher than what was assumed in our modelling, then we can expect an increase in benefits for the 1400MW option."

249 Transpower response to RFI004 – Demand and generation scenarios, pp.6-7.

250 Transpower response to RFI013 – LNG plant impact on investment test.

D73 Regarding the assumptions surrounding the solar generation modelling Transpower note that:[251]

D73.1 our rooftop solar assumptions are not based on the original 2019 EDGS. Instead, they reflect updated EDGS variations developed through extensive consultation in 2020–2021 and applied in NZGP1 and updated for this MCP. These updated assumptions result in higher distributed generation uptake than both EDGS2019 and the recent MBIE 2024 EDGS; and

D73.2 we have assumed 3.2 – 6.4 TWh of rooftop solar generation across the modelled scenarios, compared with 2.3 – 4.6 TWh in EDGS 2019 and 2.1 – 4.0 TWh presented in EDGS 2024.

D74 Transpower notes that in general its modelling anticipates strong growth in distributed solar that is consistent with recent observed trends. Transpower also note that rooftop solar modelling assumptions have more impact on energy demand rather than peak demand, which it concludes is a driver for the HVDC capacity need.

D75 Finally, Transpower notes that its grid scale solar modelling assumptions “significantly exceeds those in the 2019 EDGS” and that by 2050 “the HVDC proposal scenarios feature between 2.6 GW and 4.8 GW of installed solar capacity. By contrast the 2019 EDGS solar ranges from 0.1 GW to 1.1 GW.”[252]

D76 We are satisfied that Transpower has addressed the points raised by Meridian about its gas supply modelling and solar uptake assumptions, and the impact this has on the quantification of the market benefits.

D77 Transpower also discuss its continued use of 2019 EDGS updates to support its MCP applications, rather than the recent 2024 EDGS, stating that “the EDGS 2024 scenarios are provisional, as we are still in the process of implementing and reviewing these in our demand forecasting models, including reviewing the incorporation of new step changes in the scenarios.”[253]

D78 The EDGS scenarios are national energy forecasts that contain a forecast of generation type in each scenario matched to an energy demand forecast. Transpower then uses the energy forecasts to development specific GXP demand forecasts and forecasts of specific generators and generation types to match the EDGS generation energy forecasts.

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251 Transpower response to RFI004 – Demand and generation scenarios, p.7.
252 Transpower response to RFI004 – Demand and generation scenarios, p.7.
253 Transpower response to RFI004 – Demand and generation scenarios, p.3.

D79 In its proposal, Transpower discuss the use of 2019 EDGS updates over the 2024 EDGS and the impact of this. In recent MCP applications, Transpower has been continually updating the 2019 EDGS variations as more information comes to light, particularly generation development plans and the costs of these, which are inputs into its market modelling.

D80 Transpower states that:[254]

> In July 2024, MBIE released a new version of EDGS. We have continued to base our analysis for this project on the 2019 EDGS Variations we have developed and consulted on as the foundation of our analysis. Our view is that the 2019 EDGS Variations and our assumptions presented below provide a suitable basis for assessing this project. We note that the long-term national energy demand forecast range is broadly similar between the 2024 EDGS and the 2019 EDGS variations

**Generation scenarios – other specific generation assumptions**

D81 The Fonterra short-list consultation submission raised questions about specific generation assumptions Transpower had made. Fonterra noted that the:[255]

D81.1 "recent announcement of the staged decommissioning of the Whareroa and Edgecumbe cogeneration plants, the decommissioning data in Table 5 in Attachment 1 should reflect a 2026 date, not 2033 and 2038;"

D81.2 "geothermal assumptions of re-injection and cost reduction in the Growth scenario do not seem appropriate when compared to the other scenarios. Re-injection and cost reduction assumptions should be included in the Environmental and Disruptive scenarios"; and

D81.3 "baseload gas thermal generation plant availability post-2030 should be revisited as there remains a strong likelihood that baseload gas thermal plant will be fully decommissioned by 2030."

D82 Regarding Whareroa and Edgecumbe cogeneration plant, Transpower notes that it considered updating the retirement assumptions to reflect the 2026 closure dates but "elected not to, as we believe this change is not material to our benefits quantification".[256] Transpower's reasons included that:

D82.1 these cogeneration plants are relatively small and contribute significantly less than their nameplate capacities – approximately 2 MW for Edgecumbe and ~30 MW for Whareroa;

D82.2 the modelling assumes that any lost generation will be compensated by other generation builds in the expansion plan;

254 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 2 – Need, demand and generation scenarios, Section 2, p.14, available here.

255 *Fonterra*, HVDC Stage 1 MCP short-list consultation submission, p.1, available here.

256 Transpower response to RFI004 – Demand and generation scenarios, p.3.

D82.3 benefits are quantified over 2031–2060, so the assumed longer operation only affects a small portion of the analysis period; and

D82.4 the early retirement does not materially change system costs or the relative benefits of the HVDC options.

D83 While Transpower acknowledged the announced closures, it noted that "the impact on the investment test results is immaterial given the small injection and the long-term nature of the benefits analysis."

D84 Given Transpower's stated view of the limited impact on the investment test results, we consider Transpower's modelling approach is reasonable.

D85 Regarding the geothermal re-injection cost assumption, Transpower state that the effect of different re-injection cost assumptions is made across all scenarios in its modelling to capture uncertainty. In Transpower's view, "there is uncertainty around the extent to which emissions re-injection and cost efficiencies will be achieved for geothermal generation, and so it makes sense to not include this in all scenarios."[257]

D86 One of the key assumptions is how long base load thermal will operate. Transpower explain that "Our modelling assumes retirement of existing gas plants over time, with major decommissioning occurring through the 2030s (see Attachment 2, Section 4.4 and Table 5). For example, the E3P gas turbine generator at Huntly is assumed to retire in 2037, and other gas units progressively retire thereafter."[258]

D87 Transpower considered modelling all base load generation being retired before 2030 but elected not to do so because:[259]

D87.1 uncertainty remains about the future of gas and "while there is a strong likelihood of accelerated gas retirements, recent market developments (e.g. the Government's procurement process for LNG infrastructure) indicate that baseload gas generators could remain operational into the 2030s.";

D87.2 the modelling "assumes the closure of the Rankine units in 2030 and the combined cycle gas generator E3P continues to operate until 2037." However, the recent establishment of the Strategic Energy Reserve underpins the operation of the Rankine units into the mid-2030s. This extension of coal fired generation is likely to compensate for an earlier retirement of the gas fuelled E3P.

257 Transpower response to RFI004 – Demand and generation scenarios, p.4.
258 Transpower response to RFI004 – Demand and generation scenarios, p.4.
259 Transpower response to RFI004 – Demand and generation scenarios, pp.4-5.

D88 Transpower concludes that the assumption there is substitution in generation firming does not bias its benefits analysis. Transpower's view is that base load firming generation is going to be necessary in the near to medium term, but that the retirement assumptions (whether this is before 2030 or in the late 2030's) do not materially affect the investment test results, as the study horizon extends out to 2060.

**Generation scenarios – solar generation assumptions**

D89 As we reviewed the MCP, we wanted to understand the basis for some of Transpower's committed generation solar penetration assumptions. We considered that Transpower's assumption that, between 2025 and 2027, 1300 MW of grid scale solar would locate in the South Island may be optimistic and perhaps bias the economic analysis. We also wanted to understand how these assumptions were consistent with the same assumptions made in the recent USI MCP.[260]

D90 Transpower responded with additional information about this assumption noting that its list of committed generation included actual completed projects and those that it judged where developers have committed to build. This includes commissioned projects and those that are considered 'under delivery'.[261]

D91 Transpower note that "the assumed committed South Island solar projects have either now been completed (Solar_ASB_1 which is the Genesis solar farm at Lauriston) or is under construction (Kowhai Park)" and that its view that "the assumed committed projects are still valid, although the completion of some may be delayed."[262]

D92 Further, Transpower note that the committed projects are "largely aligned with the modelling undertaken for the Upper South Island (**USI**) MCP, although they reflect slightly more up to date information. The committed generation assumptions for this project were reviewed in early 2025, and the completion timing was based on the best information available at this time. Overall, the assumed generation development in the USI is consistent between the investigations."[263]

D93 Transpower conclude by stating that if these committed projects did not go ahead then it would expect to see the development of other substitute generation projects to meet the assumed demand growth and that because the benefit quantification occurs over the 2031-2060 timeframe, minor discrepancies surrounding the timing of near-term generation developments will not materially affect the analysis outcomes.

260 The Upper South Island MCP proposal and our decision is available here.
261 Transpower response to RFI004 – Demand and generation scenarios, pp.10-11.
262 Transpower response to RFI004 – Demand and generation scenarios, p.10.
263 Transpower response to RFI004 – Demand and generation scenarios, p.10.

D94 Transpower notes that the economic impact of its solar assumptions in the South Island is not a key driver in the economic assessment of the HVDC link at 1400 MW. Rather, the "benefits which arise from 1400 MW HVDC are due largely to flexible South Island hydro generation displacing more expensive thermal generation in the North Island. These periods do not typically coincide with high solar generation."[264]

D95 Transpower also provided additional information about the dispatch assumptions it had made for solar generation and Battery Energy Storage Systems (**BESS**). Solar dispatch is determined by solar irradiation profiles by location and time, using Global Solar Energy Estimator (**GSEE**) irradiance data.

D96 For BESS, the charge and discharge cycles are optimised by the market dispatch software to minimise system costs. This ensures that batteries charge in off peak periods and discharge during high return peak periods.

**Generation scenarios – generation stack assumptions**

D97 We also tested Transpower's generation stack assumptions. These are assumptions of capital and operating costs for various generation types and influence a modelled build plan. This build plan also affects investment test outcomes.

D98 In its proposal, Transpower state that "the basis for our generation stack is the generation stack reports procured by MBIE in 2020".[265] Our view is that a 2020 generation cost report would be out of date and we wanted to understand if Transpower was using the most recent generation cost information in its modelling.

D99 Transpower acknowledged that the generation stack must reflect current market conditions and technology cost trends. To ensure alignment with projects actively progressing in the market Transpower has updated the 2020 information by:[266]

D99.1 applying adjustments to capital costs using CPI and international benchmarks to reflect recent global cost trends;

D99.2 commissioning BECA and Concept Consulting to undertake a comprehensive update of the generation stack, including:

D99.2.1 likely generation projects and locations;

D99.2.2 updated build costs and operating costs based on recent market data and international outlooks; and

D99.2.3 validation against the Transpower pipeline and available industry information.

264 Transpower response to RFI004 – Demand and generation scenarios, p.10.
265 Transpower response to RFI004 – Demand and generation scenarios, p.5.
266 Transpower response to RFI004 – Demand and generation scenarios, p.5.

D100 Transpower notes that the updated generation stack assumptions will be explicitly published as part of its 2026 Transmission Pricing Methodology (**TPM**) Assumptions Book and will be used in future major capex proposals.

**Demand scenarios**

D101 Electricity demand forecasts are primarily used to predict the investment need date of demand driven projects, and future investments of modelled projects. The need dates of modelled projects affect the electricity market costs and benefits of the investment options considered especially for investments to meet demand growth.

D102 EDGS does not provide a forecast of megawatt (**MW**) demand by region or GXP but instead provides national level forecasts of energy demand. When Transpower carries out power systems and economic analysis in support of a MCP proposal, it usually estimates peak demand forecasts by GXP, by matching the national energy forecasts with known GXP demand levels, and growth trends.

D103 In this MCP, the effect of the demand forecast is not as important as the assumptions (capacity, location and timing) made in the generation scenario modelling. While the demand forecast is important, the justification of an HVDC link capacity upgrade is more about the ability of the HVDC link to transfer cheaper hydro and renewable energy from the South Island to the North Island, especially during peak periods.

D104 Transpower has used a similar process it has used in recent MCP applications to align the national and regional energy demand forecasts. In arriving at its demand forecasts Transpower identified a range of factors that would influence demand growth. These factors include:[267]

D104.1 base demand growth driven by factors such as population increase;

D104.2 step load changes that might appear in the future from new commercial and major residential developments;

D104.3 electric vehicle (**EV**) uptake;

D104.4 uptake of residential and commercial solar photovoltaic (**PV**) panels;

D104.5 uptake of residential and commercial battery storage; and

D104.6 electrification of industrial processes, such as the conversion of coal and diesel boilers to electric boilers.

D105 Each scenario used in the proposal has different assumptions relating to each of these factors that leads to the overall variation in the forecasts.

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[267] *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 2 – Need, demand and generation scenarios, Section 3.1, p.15, available here.

D106 One key demand assumption is the future of the Tiwai aluminium smelter at Tiwai. In this MCP, Transpower has assumed that Tiwai remains until 2060 in all scenarios. This is a change to its assumption in the NZGP1 Stage 1 MCP, where Transpower assumed that the Tiwai smelter would be non-operational after 2024 in all scenarios.

D107 Transpower, in its response to an RFI, stated that it was a credible assumption that Tiwai smelter would remain in service throughout the analysis timeframe, noting that the smelter has arranged a supply contract with generators until 2044.[268]

D108 Transpower contend that it Tiwai were to exit before 2044 then it "the released South Island renewable generation would likely defer new generation build and support North Island demand. This increases reliance on HVDC transfer capability, making the HVDC upgrade more valuable than in the base case."[269]

D109 Transpower's view is that it Tiwai assumption is a conservative one and showed analysis from its NZGP1 Stage 1 MCP proposal showing that for a 2024 Tiwai exit the accrued benefits were $319 million, and $115 million for a 2034 exit.

D110 Transpower conducted additional modelling to assess the potential impact of a Tiwai Point smelter exit on benefits in the HVDC Stage 1 MCP with 1200 MW and 1400 MW capacity. The sensitivity analysis used the Disruptive scenario and assumed a Tiwai exit at the beginning of 2044.

D111 Transpower concluded that:[270]

> if the aluminium smelter at Tiwai Point exits, there would be a substantial uplift in market benefits from increasing HVDC northward capacity. Specifically, under the Disruptive scenario, a Tiwai exit in 2044 increases the gross benefits of option 3 from $206 million to $443 million.

D112 The additional benefits are due to reduced thermal operating costs, avoided reserve payments and avoided demand response deficit costs. Transpower's interpretation of this analysis is that "the smelter's exit frees up significant flexible South Island hydro generation. This hydro capacity can then be used to firm North Island intermittent generation more effectively, reducing reliance on expensive thermal generation and avoiding deficits (which is primarily demand response)."[271]

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268 Transpower response to RFI004 – Demand and generation scenarios, pp.10-14.
269 Transpower response to RFI004 – Demand and generation scenarios, p.10.
270 Transpower response to RFI004 – Demand and generation scenarios, p.14.
271 Transpower response to RFI004 – Demand and generation scenarios, p.14.

**Demand and generation scenario variations must be feasible and reasonable**

D113 Clause D3(3) of Schedule D of the Capex IM sets out a non-exhaustive list of the factors that Transpower must have regard to for a scenario variation to be a "feasible and reasonable" variation of EDGS. Those factors include existing and forecast demand, the grid reliability standards (**GRS**), the value of expected unserved energy, and transfer capacities and capabilities of the grid.

D114 Some of these requirements are more relevant to the demand scenarios and some are more relevant to the generation scenarios.

D115 The HVDC Stage 1 MCP is a proposal to enhance HVDC transmission capacity that is primarily driven by the energy market access to lower cost renewables generation in the South Island. As such, the generation forecasting assumptions drive the economics of the HVDC link capacity upgrade to 1400 MW, so it is a key assumption in the application of the investment test.

D116 We consider that Transpower has made a reasonable case for its use of an update to the 2019 EDGS because:

- D116.1 the 2024 EDGS contains limited regional demand and generation information and this regional and GXP allocation is already modelled in its 2019 EDGS update;[272]
- D116.2 the 2019 EDGS update forecasts used in the proposal were consulted on as part of the proposal process;
- D116.3 Transpower has addressed the key points raised in submissions and in response to our RFI questions;
- D116.4 Transpower did not see a need to move to the 2024 EDGS as, at a high level, the scenarios appeared to have similar levels of growth; and
- D116.5 Transpower understands the pipeline of new generation type and location through its connection enquiries process, so holds the most up to date information about likely generation in the near to medium term.

D117 We also agree with the specific generation modelling assumptions Transpower has made, and the short-list submitter comments have been reasonably explained.

**Transpower has weighted the scenarios**

D118 The Capex IM default setting for scenario use in the investment test analysis is that each of the five EDGS scenarios has equal weighting.[273]

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[272] Transpower response to RFI004 – Demand and generation scenarios, p.3.

[273] *Transpower NZ Ltd*, USI Stage 1 MCP Attachment 4 – Application of the investment test, Section 2, p.4, available here.

D119 The investment test uses a weighted average of net electricity market benefits under each demand and generation scenario.

D120 In the proposal, Transpower has proposed different scenario weightings, specifically:[274]

D120.1 the Global scenario is weighted at 0% because the Reference scenario provides an adequate lower bound assumption for the lower demand growth; and

D120.2 the remaining scenarios are weighted at 25%.

D121 Transpower state that "between 2030 and 2050 the Global scenario projects national demand growth of just 0.6% per annum, and the Reference scenario 0.8% per annum. These rates are low in the context of ongoing electrification and decarbonisation trends, which are expected to drive higher electricity demand."[275]

D122 Transpower note that in its short-list consultation submitters generally agreed with its approach.

D123 In its short-list consultation submission, the BEC noted that "the TIMES-NZ 2.0 model shows that in both its Tūi and Kea scenarios electricity demand roughly doubles by 2050 due to electrification of transport and industry" and that "an upgraded HVDC link is essential to integrate new renewable generation, without it the grid will struggle to accommodate increased generation."[276]

D124 BEC explain that the TIMES-NZ 2.0 model was developed in conjunction with the Energy Efficiency and Conservation Authority (**EECA**) and "over 60 partners from across the energy sector, including private and public sector entities" to develop TIMES-NZ. This was "to stimulate future energy thinking by providing an integrated overview of New Zealand's energy sector" that is "related to climate change actions."[277]

D125 In its short-list consultation submission, Fonterra suggested that the Reference and Global process heat scenarios were "too low" given its potential de-carbonisation plan.[278] Fonterra suggested that the Environmental scenario was more likely to reflect New Zealand's energy future and should be weighted at 50%, while Vector suggested that there was scenario weighting bias for higher demand outcomes to drive investment in the fourth cable.[279]

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274 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 7 – Investment test, Section 2.1, p.5, available here.

275 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 7 – Investment test, Section 2.1, p.5, available here.

276 *BEC*, HVDC Stage 1 MCP short-list consultation submission, p.4, available here.

277 *BEC*, HVDC Stage 1 MCP short-list consultation submission, p.6, available here.

278 *Fonterra*, HVDC Stage 1 MCP short-list consultation submission, pp.1-2, available here.

279 *Vector*, HVDC Stage 1 MCP short-list consultation submission, p.4, available here.

D126 Transpower responded to the Vector submission stating that, of the four scenarios it tested, these were weighted equally when it applied the investment test and that the "range of potential energy futures may lean conservative". Transpower's view is that "an equal weighting approach provides a prudent and balanced basis for assessing long-term investments."[280]

D127 We agree with Transpower's approach and the scenario assumptions it has made. With reference to the sensitivity analysis results, Transpower has demonstrated that when each of the remaining four scenarios is tested separately, each result in the fourth cable option providing a higher electricity net market benefit than the three-cable 'like-for-like' option.[281] This validates Transpower's weighting assumption.

**Scenarios - conclusion**

D128 In conclusion, we are satisfied that Transpower has met the Capex IM clause D3(2) and D3(3) requirements. We agree that the demand and generation scenario variations are reasonable variations of the EDGS forecasts, and that the scenario weightings it has applied are reasonable.

**Investment options Transpower considered**

D129 The Capex IM requires that:

D129.1 the number of investment options must be appropriate given the magnitude of the estimated expenditure, and the complexity of the investment need associated with the proposed investment;[282] and

D129.2 with respect to each investment option, the specificity of information and rigour and comprehensiveness of the analysis, must be commensurate with the estimated expenditure and complexity of the option.[283]

D130 The Capex IM defines an investment option as a technically feasible solution designed to facilitate or meet a specific investment need.[284]

280 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 7 – Investment test, Section 2.1, p.5, available here.

281 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 7 – Investment test, Table 10, p.15, available here.

282 Capex IM, clause 7.4.1(2).

283 Capex IM, clause 7.4.1(3).

284 Capex IM, clause 1.1.5(2).

### Whether the number of investment options is appropriate given the magnitude of the estimated expenditure and the complexity of the investment need

D131 In its 23 April 2025 Notice of Intention (**NOI**) to us Transpower argued that, because it had extensively consulted on HVDC link development options in the recent NZGP1 Stage 1 MCP, and that there were a limited number of HVDC upgrade options that could be considered feasible, that it was reasonable to exclude the long-list consultation stage in this proposal,[285] and proceed directly to the short-list consultation.[286] We agreed with Transpower's reasoning.[287]

D132 In its proposal Transpower explain that the investment need is driven by "the deteriorating condition of the HVDC submarine cables (as they approach the end of their design life) and the control systems have reached obsolescence and will no longer be supported by the manufacturer".[288] Additionally, Transpower is using the opportunity to consider the installation of a fourth cable and associated works to raise HVDC link cable capacity to 1400 MW to match the installed converter capacity.

D133 In its short-list consultation, Transpower selected three investment options that it would apply the investment test to. The three short-list options are set out in Table D1.

**Table D1 Short-list investment options[289]**

| Option | Description of transmission developments |
|---|---|
| 1 | **Base case option**<br>The HVDC submarine cables, control systems and termination stations would not be upgraded. Over time, as components fail, the HVDC link would be decommissioned. |
| 2 | **1200 MW option**<br>Replacement of the three submarine cables with 1200 MW capacity, along with necessary seismic and engineering upgrades to the termination stations and new cable storage facility. |
| 3 | **1400 MW option**<br>Replacement of the three submarine cables with four submarine cables to support 1400 MW north capacity, accompanied by necessary seismic and engineering upgrades to the termination stations, Benmore filter, Pole 2 short-term overload scheme and new cable storage facility. |

285 Capex IM, clause 8.1.3(2)(b).
286 *Transpower New Zealand Ltd*, Letter of Notification under clause 3.3.1(1) available here.
287 *Commerce Commission*, letter to Transpower agreeing matters under clause 3.3.1(2) of the Capex IM, 22 May 2025, available here.
288 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 2 – Need, demand and generation scenarios, Section 1.3, p.4, available here.
289 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 4 – Short list of investment options, Table 2, p.14, available here.

D134 We are satisfied that the shorted-list investment options set out in Transpower's proposal, provide a reasonable number of investment options for analysis and testing, using the investment test.

D135 This is because they:

D135.1 cover the limited number of potential solutions, including implementing options to increase transmission capacity of existing assets and a run to failure option;

D135.2 covers a range of options that demonstrate the economic value of the HVDC link and the economic value of a capacity upgrade; and

D135.3 will meet the investment need by enhancing transmission capacity to allow renewable energy developments in the South Island to access demand need in the North Island out to 2060.

D136 In its short-list submission, Vector suggested that the 4th cable could be deferred as it would retain optionality. Vector stated it "does not claim that these option value benefits would necessarily outweigh the economies Transpower has identified. They may or may not. What matters is that those benefits are real and should be included in the assessment." [290]

D137 In its analysis, Transpower addressed this point concluding the 4th cable deferral option was not short-listed because it will "result in higher overall costs and lower net benefits compared to installing all four cables together" because:[291]

D137.1 "future procurement of a single HVDC submarine cable may be unfeasible or highly risky due to limited global supply and increasing demand";

D137.2 "if staged, the fourth cable would still need to be ordered now, shipped to New Zealand, and stored – incurring significant handling, storage, and risk management costs"; and

D137.3 a "second vessel mobilisation would further increase costs (including additional outages), effectively negating any option value."

D138 Vector also noted that "there is a distinct possibility that the fourth cable may prove to be unnecessary – at least for some of the investment's lifespan. For example, if North Island demand or renewable development grows more slowly than Transpower's 'Growth' or 'Environmental' scenarios, the additional 200MW could remain under-used for many years while consumers, including Vector's, foot the bill for it".[292]

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290 *Vector*, HVDC Stage 1 MCP Short-list consultation submission, p.2, available here.

291 *Transpower New Zealand Ltd,* HVDC Link Upgrade Programme MCP Short-list consultation, Attachment 4 – Short-list of investment options, p.11, available here.

292 *Vector*, HVDC Stage 1 MCP short-list consultation submission, para 7, p.2, available here.

D139 While Transpower qualitatively explained that a fourth cable deferral investment option would be less economic than the options it had short-listed, we requested an economic analysis to satisfy ourselves that this was the case.[293] We discuss this analysis in our discussion of Transpower's application of the investment test later in this attachment.

### Whether, for each investment option, the specificity of information and rigour and comprehensiveness of the analysis are adequate

D140 Following our review of the proposal and supporting material, we consider:

D140.1 Transpower has provided sufficient information and supporting analysis as part of the HVDC Stage 1 MCP, including in response to our RFIs; and

D140.2 the specificity of information, and rigour and comprehensiveness of the analysis in the HVDC Stage 1 MCP, is adequate and consistent with the Capex IM.

## Our evaluation of the investment test application

D141 We outline the analysis that supports our findings and our assessment of Transpower's application of the investment test for the USI Stage 1 MCP. We have analysed how Transpower calculated the net market costs, and net electricity market benefits in its investment test application, and the sensitivity analysis it has carried out.

**Expected electricity market cost and benefit elements in the Capex IM investment test**

D142 In applying the investment test, Transpower must calculate the following for each investment option included in the MCP:

D142.1 the electricity market benefits under the relevant demand and generation scenario;

D142.2 the electricity market costs under the relevant demand and generation scenario;

D142.3 the net electricity market benefit for the relevant demand and generation scenario; and

D142.4 the expected net electricity market benefit.

D143 Under Schedule D of the Capex IM:

D143.1 'electricity market benefit or cost element' means any of the market benefits received, or market costs incurred by consumers, during the calculation period under the relevant demand and generation scenario, that will affect net electricity market benefits;[294]

[293] Transpower response to RFI012 – Fourth cable deferral economic analysis.
[294] Capex IM, clause D4(1).

D143.2 the 'net electricity market benefit' is, in respect of an investment option, applied to a demand and generation scenario, its aggregated quantum of each electricity market benefit or cost element, less its aggregated quantum of each project cost; and

D143.3 the 'expected net electricity market benefit', in respect of an investment option, is the weighted average of the net electricity market benefit under each relevant demand and generation scenario.[295]

D144 In evaluating Transpower's application of the investment test, we assessed whether Transpower reasonably estimated, for each investment option in the proposal:

D144.1 the electricity market benefits;

D144.2 the electricity market costs; and

D144.3 the net electricity market benefit, and the expected net electricity market benefit.

D145 In the following sections, we outline the analysis that supports our findings and our assessment of Transpower's application of the investment test. We have analysed how Transpower has calculated the net market costs, and net electricity market benefits in its investment test application, and the sensitivity analysis it has carried out.

**Transpower general approach to modelling market cost and benefit elements**

D146 Transpower explain in its proposal that its economic modelling quantifies market cost and benefit elements in electricity market dispatch simulations for the investment options it has considered against a 'Base Case'.

D147 The first option (option 1) Transpower has labelled the "Base case", where it assumes that, as existing HVDC link cables fail, they are not replaced. The second option (option 2) is the like-for-like replacement option, where HVDC link capacity is maintained at its present 1200 MW capacity. The third option (option 3) is the proposed investment, where HVDC link capacity is increased to 1400 MW, with a fourth cable and associated works installed to increase control functionality.

D148 The modelled market costs are dominated by the capital costs of options 2 and 3 and the avoided higher electricity market costs associated with option 1.

D149 The capital costs include modelled project costs for transmission projects to ensure the HVDC link is technically functional for options 2 and 3 out to 2060.

295 Capex IM, clause D2(1).

D150 The modelled market benefits are quantified using electricity market dispatch software, with the benefits of investment options 2 and 3, providing significantly lower costs when compared to option 1. Transpower has characterised the lower market costs as electricity market cost savings.

D151 The general market modelling approach Transpower has taken has two steps:[296]

D151.1 step one is to model generation expansion plans to identify the lowest-cost combination of new generation projects required to supply future demand under the scenarios considered and for each option.

D151.2 step two is to carry out simulations to estimate the electricity system market costs for the option generation expansion plan and for each scenario.

D152 The generation expansion plan and dispatch assumptions and modelling are central to the economics of upgrading the HVDC link to 1400 MW. The market dispatch analysis results determine if a 1400 MW capacity HVDC link provides a higher net market benefit than a 1200 MW link, so the assumptions that underpin the generation expansion modelling are key to this proposal passing the investment test.

**Generation expansion planning**

D153 Transpower states that its generation expansion modelling builds new generation as required to meet forecast demand while minimising generation dispatch costs. New generation is selected from "a generation stack of potential projects with the overall objective of minimising the cost of electricity over the period being considered."[297]

D154 Transpower considers that these least-cost generation plans are representative of what the market would deliver in future scenarios but recognises that actual generation investment decisions will be governed by availability of capital, and wholesale electricity price forecasts, for example.

D155 The expansion plans are adjusted to optimise new modelled generator capital and operating cost estimates, and to ensure that new generation build is revenue adequate eg the timing of new generation build is adjusted so that modelled revenue covers operating cost and capital repayment estimates.[298]

D156 We consider that Transpower has carried out a rigorous process to identify its generation expansion plans include consulting on the scenarios in the short-list consultation. These plans set the economic platform for the benefits that are used to justify the proposed upgrade to 1400 MW.

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296 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 6 – Benefits modelling, Section 1.1, p.4, available here.

297 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 6 – Benefits modelling, Section 1.2.1, pp.4-5, available here.

298 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 6 – Benefits modelling, Section 1.2.2, pp.5-6, available here.

**Generation dispatch simulation**

D157 To determine the market dispatch costs for each investment option and scenario, Transpower uses Stochastic Dual Dynamic Programme (**SDDP**) software developed by PSR.[299] SDDP modelling is appropriate for use in New Zealand, because it models the value of water storage at each hydro generation plant, wind generation variability, grid scale batteries, and geothermal, thermal and co-gen process heat based generation.[300]

D158 For this proposal, Transpower has carried out SDDP market dispatch simulations at a resolution of one hour over the modelling period to 2060, for each scenario and each investment option considered. Transpower has taken this approach to model generation and demand variability effects and to more effectively capture peak demand pricing impacts.

D159 The Transpower SDDP model incorporates a detailed representation of the transmission network to mimic actual market conditions, and Transpower explains how it has accounted for specific network effects such as:

D159.1 AC network constraints are not modelled in this proposal as it is focussed on HVDC capacity only. The assumption is that wider AC network constraints affect options 2 and 3 equally and that no AC network constraints distinguish between them; and

D159.2 AC network and HVDC losses are not expressed separately but incorporated directly as a demand effect within the SDDP model.

D160 The HVDC overload ratings vary between investment options and play a role in determining the HVDC's contribution to instantaneous reserves costs. Transpower notes that the "HVDC link plays an important role by facilitating the sharing of instantaneous reserves (hereafter, simply reserves) between the North and South Islands, and setting the risk and need for reserves when transferring at high capacities."[301] This reserves impact outcome is particularly important as it has been used to demonstrate that the Pole 2 short-term overload investment significantly reduces market reserves costs.

D161 We consider that Transpower's use of SDDP as a means to model market dispatch outcomes is well understood and is at a mature level. SDDP has been used in major capex proposals before the Capex IM was enacted in 2012, so Transpower has decades of modelling experience with this specialist software.

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299 PSR is a global provider of energy consulting and computational models. PSR carries out research and development for optimization and data analytics solutions for the energy sector.

300 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 6 – Benefits modelling, Section 1.3.3, p.7, available here.

301 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 6 – Benefits modelling, Section 1.3.5, p.8, available here.

## Expected electricity market cost and benefit elements in the proposal

D162 Clause D4 of Schedule D of the Capex IM sets out the electricity market cost or benefit elements that Transpower must consider in the investment test.

D163 Clause D4(1)(m) allows Transpower to include in its application of the investment test, any other benefit or cost occurring in the electricity market proposed by Transpower, prior to its consultation on the short-list of investment options, and agreed to by the Commission.

**Cost and benefit elements Transpower has modelled**

D164 Transpower has modelled the effect of the following categories of electricity market costs for the investment options it considered.

D164.1 **capital costs** of proposed investments, investment options and modelled projects;[302]

D164.2 **network operation and maintenance (O+M) costs**; and

D164.3 **HVDC and AC network losses**.

D165 Transpower has modelled the effect of the following categories of electricity market benefits for the investment options it considered namely:

D165.1 relative **generation capex costs**;

D165.2 relative **generation operational costs** which include:

D165.2.1 thermal fuel and thermal O+M costs;

D165.2.2 emission costs such as carbon pricing;

D165.2.3 deficit costs associated with voluntary and involuntary demand curtailment; and

D165.2.4 instantaneous reserves costs.

D166 We describe and evaluate the modelling Transpower has undertaken to model the market cost and benefit elements it has identified and quantified for application in the investment test.

302 Modelled projects are projects modelled by Transpower in its analysis to ensure the transmission network capacity is able to meet the investment need over the analysis timeframe. Modelled projects do not form part of the MCP application.

## Electricity market costs

### Capital costs of proposed investments, investment options and modelled projects

D167 While Transpower has to some extent used its TEES cost estimation framework to estimate some of the HVDC Stage 1 MCP costs, and modelled project capital costs, most of the costs in this proposal are for unique investments that are specific to HVDC systems.

D168 As such, these costs are reliant on manufacturer quotations, external expert consultants and in-house bespoke designs. While we consider there is considerable cost risk associated with this project, a conclusion reached also by GHD in its expert review, we have accepted that Transpower's capital cost estimates are reasonable for this stage of the project. We discuss the cost estimation process at length in Attachment C.

D169 The assumed proposal modelled projects, their capital costs and assumed installation dates are set out in Table D2.[303] These are not projects Transpower is seeking approval for. They are modelled in Transpower's analysis to ensure the power system is credibly operational over the analysis timeframe and to enable longer-term costs and benefits to be captured.

**Table D2 Proposal modelled projects**

| Proposed modelled project | Modelled commissioning year | Undiscounted capital cost ($m) |
|---|---|---|
| Approved HVDC NZGP1.1 projects (reactive plant, filter banks, associated equipment) | 2028 | 84.4 |
| Pole 3 mid-life refurbishment | 2032 | 89.0 |
| Dismantle Pole 2 | 2041 | 57.5 |
| Replace Pole 2 with Pole 4 | 2041 | 1,150.0 |
| Dismantle Pole 3 | 2057 | 57.5 |
| Replace Pole 3 with Pole 5 | 2057 | 1,150.0 |
| Control system replacement | 2051 | 253.5 |
| Filter bank at BEN 2055 (Option 3 only) | 2056 | 19.7 |

303 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 7 – Investment test, Table 2, pp.7-8, available here.

D170 The proposal Stage 1 and 2 projects, their capital costs and assumed installation dates are set out in Table D3.[304]

**Table D3 Proposal Stage 1 and 2 projects**

| Proposed project component | Expected cost estimate ($m 2025) | Stage |
|---|---|---|
| Supply and install of four submarine cables | 760.4 | Stage 1 |
| Cable termination station replacement | 134.5 | Stage 1 |
| Benmore filter bank | 19.7 | Stage 1 |
| Pole 2 short-term overload scheme | 12.7 | Stage 1 |
| New cable storage facility | 11.6 | Stage 1 |
| Project investigation costs | 19.5 | Stage 1 |
| HVDC control system replacement | 253.5 | Stage 2 |
| Recovery of decommissioned cables | 131.8 | Stage 2 |
| Provision for recovery of new cables | 131.8 | Stage 2 |
| **Total** | 1,475.4 | |

D171 The comparison of the discounted capital costs for the three options considered, including modelled projects is shown in Table D4.

**Table D4 Investment option discounted capital costs ($million 2025)**

| Investment option | Capital cost | Modelled project capital cost |
|---|---|---|
| Option 1 – Base case | 267.3 | 0.0 |
| Option 2 – 1200 MW HVDC | 1,002.8 | 645.1 |
| Option 3 – 1400 MW HVDC | 1,113.2 | 646.5 |

304 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 7 – Investment test, Table 5, pp.9-10, available here.

### Operation and maintenance costs

D172 Transpower has assigned operation and maintenance costs (**O&M**) for each existing asset, the transmission investment options considered, and each modelled project in its economic analysis.[305] Present value O&M cost estimates have been provided (see Table D5) and illustrate that they do not distinguish between options 2 and 3.

**Table D5 O+M costs for each option ($million 2025)**

| Investment option | O+M cost |
|---|---|
| Option 1 – Base case | 207.9 |
| Option 2 – 1200 MW HVDC | 347.5 |
| Option 3 – 1400 MW HVDC | 347.5 |

D173 In its proposal, Transpower discuss its O+M calculation approach stating that:[306]

> O&M costs of investment options: While there is no significant O&M cost difference between the 1200 MW and 1400 MW cable replacement options (options 2 and 3), the no investment and decommissioning option (option 1) has considerably lower O&M costs because these costs cease after the HVDC link is decommissioned. We have assumed annual O&M costs for the HVDC link of $20m, based on the average forecast O&M spend on the HVDC link over the next 30 years.5 We consider this is a to be a reasonable P50 estimate of annual O&M costs for options 2 and 3.

D174 Additionally, as part of its market dispatch analysis to ascertain the benefits of new generation, Transpower has modelled variable operating and maintenance costs associated with the different generation types.

D175 While we did not evaluate Transpower's assessment of O&M costs in detail, because these do not have a material impact on the results of the investment test (ie that they do not distinguish between the 1200 MW and 1400 MW options), we are satisfied that Transpower has reasonably modelled and accounted for O&M costs in the proposal.

### HVDC and AC network losses

D176 To estimate HVDC losses, Transpower has used a simple DC circuit model within the SDDP market model which includes Pole 2, Pole 3 and an earth return. Transpower has not expressed the HVDC losses as a separate cost in its investment test results but included their effect in the operational costs in each market dispatch simulation.

D177 AC network losses are accounted for in the market dispatch solution as having a demand effect in the solution algorithm.

305 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 7 – Investment test, Table 6, p.10 available here.

306 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 7 – Investment test, Section 3.1, p.8 available here.

### Total costs

D178 Table D6 presents the present value (using the Capex IM discount rate of 5%) of all modelled costs for each investment option through to 2060.

**Table D6 Total discounted costs for each option ($million 2025)**

| Investment option | Capital cost | Modelled project capital cost | O+M cost | Total cost | Relative cost |
|---|---|---|---|---|---|
| Option 1 – Base case | 267.3 | 0.0 | 207.9 | 475.2 | -1,520.2 |
| Option 2 – 1200 MW HVDC | 1,002.8 | 645.1 | 347.5 | 1,995.4 | 0.0 |
| Option 3 – 1400 MW HVDC | 1,113.2 | 646.5 | 347.5 | 2,107.2 | 111.8 |

## Electricity market benefits

D179 We discuss the calculation of the electricity market benefits Transpower has identified and quantified in its economic analysis. These benefits are largely the result of market dispatch analysis and the quantified effect of an out of merit order generation build in the North Island when the HVDC link is not upgraded over time as cables fail.

### Demand curtailment

D180 In its analysis, Transpower has modelled the deficit that occurs if there is not enough generation to meet peak demand and during dry hydro inflow periods when there is not enough energy to meet winter peak demand.[307]

D181 Transpower has termed this cost the deficit cost in its modelling and has assumed that different demand tranches have different costs. These cost tranches are set out in Table D7.

D182 Transpower states that each tranche is intended to model the costs that "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."[308]

**Table D7 Demand curtailment tranche assumptions[309]**

| Proportion of hourly demand | Cost |
|---|---|

[307] *Transpower NZ Ltd*, USI Stage 1 MCP Attachment 6 – Benefits modelling, Section 2.3, p.10 available here.

[308] *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 6 – Benefits modelling, Section 2.2.2, p.15 available here.

[309] *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 6 – Benefits modelling, Table 5, p.15 available here.

| | |
|---|---|
| First 5% of demand | $600/MWh |
| Between 5% and 10% of demand | $800/MWh |
| Between 10% and 15% of demand | $2,000/MWh |
| Greater than 15% of demand | $10,000/MWh |

D183 Transpower notes that the "total amount of deficit is a very small proportion of the total amount of demand served to consumers. It occurs infrequently and for short periods of time."[310]

D184 Following our review, we agree that the demand curtailment cost tranches Transpower has used in this proposal are reasonable and consistent with previous proposal assumptions.

### Reduction in generation capex costs

D185 Transpower has calculated a 'reduction in generation capex costs' as a benefit that accrues to options 2 and 3. Transpower argues that in the base case option (option 1) the decommissioning of the HVDC results in more 'firm' generation being built in the North Island to meet demand.

D186 We sought additional information from Transpower about this reduction in generation capex benefit and the considerable value it had ascribed to it. Transpower explains that:[311]

> The capital benefits represent the avoided cost of new generation investment that would be required if the HVDC link were decommissioned. Without the HVDC, the North Island would need to build significant additional firm generation to maintain energy supply and capacity adequacy. Our modelling shows that this would involve large-scale geothermal and other generation projects, which are the most cost-effective way to replace HVDC transfer capability,
>
> By retaining and upgrading the HVDC link (options 2 and 3), these generation investments are avoided, resulting in capital benefits of $2.0–$3.3 billion. The range reflects different assumptions about future generation costs, technology mix, and timing of investment under different scenarios. These benefits are important because they represent real avoided capital expenditure and lowering costs to consumers

D187 Transpower has concluded that not only will the base case option result in an out of merit order generation build, but that additional generation will need to be built in the North Island to meet immediate demand. The South Island will have an energy surplus without the HVDC link to allow this surplus to access the North Island electricity market.

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310 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 6 – Benefits modelling, Section 2.2.2, p.15 available here.

311 Transpower response to RFI005 – Investment test analysis, pp.1-2.

D188 While the 'reduction in generation capex benefits' set out in Table D8 do not discriminate between options 2 and 3, and do not affect our analysis of whether to approve the proposal for 1400 MW HVDC link capacity, they are a component benefit in Transpower's estimate of HVDC link overall value to the New Zealand economy.

**Table D8 Reduction in generation capex benefits discounted for each option and for each scenario ($million 2025)**

| Investment option | Disruptive | Environmental | Growth | Reference |
|---|---|---|---|---|
| Option 1 – Base case | 0 | 0 | 0 | 0 |
| Option 2 – 1200 MW HVDC | 2,269 | 3,341 | 2,880 | 1,973 |
| Option 3 – 1400 MW HVDC | 2,269 | 3,341 | 2,880 | 1,973 |

### Operational costs

D189 Once the generation build plans for each scenario have been modelled, Transpower carries out market dispatch analysis using its market modelling software SDDP for each year out to 2060 and for each option. In each market dispatch simulation, which is carried out on an hourly basis, electricity market prices are calculated and compared for the three options considered. In this way the benefit of the 1400 MW HVDC link capacity can be compared with 1200 MW capacity, and the overall value of the link to the New Zealand economy.

D190 The market dispatch software determines modelled electricity market prices at each hour of the simulation. If, in the option 3 dispatch analysis, there is a lower electricity market price than option 2 (and option 1), then Transpower considers that this a benefit that accrues to option 3 (eg a reduction in operational costs).

D191 The market dispatch modelling accounts for a number of factors in the decision to dispatch a generator, including:[312]

D191.1 future changes in grid connected generation and batteries - as provided by the generation expansion plans;

D191.2 future changes to the HVDC for each investment option;

D191.3 changes in demand - arising from daily and weekly demand variations through to long-term demand growth;

D191.4 hydro inflow variability and uncertainty;

D191.5 renewable energy variability;

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312 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 6 – Benefits modelling, Section 1.3, p.6 available here.

D191.6 grid scale battery operation; and

D191.7 generator plant operational constraints - including thermal plant unit commitment and hydro plant minimum flow constraints.

D192 The modelling of hydro inflow sequences is a key assumption in this analysis because resulting operational costs can vary considerably.[313]

D193 The operational costs are evaluated "to understand how the system operates, and to consider the benefits between different investment options." Embedded within the calculation of operational costs are a number of distinct modelled cost categories, such as:[314]

D193.1 **Thermal fuel and thermal O+M costs –** fuel costs apply only to gas, biofuel, diesel and coal generators, whereas O+M costs include geothermal generation.

D193.2 **Emission costs –** emissions from fossil fuel combustion and geothermal steam have an associated cost, depending on the carbon price.

D193.3 **Deficit costs –** deficit costs arise when electricity demand cannot be met due to supply constraints (demand curtailment). These might occur during very high peak demand periods or low hydro inflows. Although these deficits are typically infrequent and short-lived, they can have significant financial and operational consequences. In these situations, consumers will be forced to curtail demand or find alternative ways of being supplied with electricity.[315]

D193.4 **Instantaneous reserves –** instantaneous reserves are required to mitigate the impact of unplanned outages. Sufficient reserves must be procured to cover defined contingencies, such as the loss of the largest generating unit in each island or the failure of a single HVDC link pole. These reserves can be provided by generation, batteries, or interruptible load. The required reserve levels include additional reserves to cover HVDC link pole outages, which are directly attributable to HVDC link operation. Enhancing the capacity of the HVDC link increases the extent to which the link can self-cover its reserve requirements, which leads to a saving in reserve costs.

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313 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 6 – Benefits modelling, Section 1.3.3, p.7 available here.

314 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 7 – Investment test, Section 3.2, p.11 available here.

315 In its consultation submission the Business Energy Council (**BEC**) asked whether demand-side response would be a more cost-effective solution than the HVDC capacity upgrade to 1400MW. Transpower has implicitly addressed the BEC suggestion in its deficit benefit modelling that factor the demand curtailment cost tranche assumptions.

D194 The Pole 2 short-term overload investment in option 3 has a particular impact on reserves costs. Transpower notes that each HVDC pole has a "overload capacity at which it can operate for short periods of time" and allows the HVDC to "self-cover its own reserve requirement to an extent. For example, if Pole 3 were to trip then Pole 2 could compensate by operating at a higher capacity for 15 minutes until the market can be re-dispatched."[316]

D195 Transpower provide a worked example of the present pole outage reserves settings and note that "Through investment in the HVDC we can increase the overload capacity of Pole 2 and enhance the ability of the HVDC to self-cover its reserve requirement. This requires an increase in the capacity of the cables connected across Pole 2 (consistent with option 3) and enhancements to the converter equipment at Benmore and Haywards."[317]

D196 This is the proposed Pole 2 short-term overload (**STOL**) scheme, and its effect is modelled in the dispatch analysis. We discuss the benefit of the Pole 2 STOL in the next sections.

D197 Following its market dispatch analysis, Transpower calculated the total operational benefits that accrue to options 2 and 3, and the incremental benefit of Option 3 vs Option 2 (see Table D9).

**Table D9 Total operational benefits of Options 2 and 3 vs Option 1 ($million 2025)**

| Investment option | Disruptive | Environmental | Growth | Reference |
|---|---|---|---|---|
| Option 1 – Base case | 0 | 0 | 0 | 0 |
| Option 2 – 1200 MW HVDC | 2,462 | 2,467 | 1,975 | 1,623 |
| Option 3 – 1400 MW HVDC | 2,668 | 2,702 | 2,104 | 1,765 |
| Option 3 vs Option 2 | 206 | 235 | 130 | 142 |

### The operational benefits of maintaining HVDC link capacity at 1200 MW

D198 Transpower analysis suggests that the operational benefits of maintaining HVDC link capacity at 1200 MW are significant and are largely due to costs savings in "thermal fuel and emissions costs".[318]

316 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 6 – Benefits modelling, Section 2.1.3, p.12 available here.

317 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 6 – Benefits modelling, Section 2.1.3, p.13 available here.

318 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 6 – Benefits modelling, Section 4.5.1, p.30 available here.

D199 Transpower explain that:[319]

> Without the HVDC, more geothermal and/or thermal generation is required to supply North Island demand. The geothermal generation runs year-round as baseload and the thermal generation is flexible and ramps up over winter months. Both generation types have operational costs: for geothermal these are emissions costs, and for thermal there are fuel, operating and maintenance and emission costs.

D200 Transpower further explain that:[320]

- D200.1 "benefits from avoided operational costs begin to occur from 2031" when the "failure of a submarine cable and reduced Northwards transfer in the Base Case/option 1" is assumed to occur;
- D200.2 "significant benefits begin to accrue in 2038 when the HVDC is assumed to be decommissioned in the Base Case/option 1";
- D200.3 there is "some variance across the modelled scenarios" which is attributed to a "combinations of scenario assumptions (e.g., carbon and fuel costs) and differences in generation mix"; and
- D200.4 "the level of deficit is highly sensitive to the timing of generation build and small differences between the expansion plans for Base Case/option 1 and option 2 manifest as variance in deficit costs".

D201 Transpower present its dispatch modelling economic results in Figure 12 in the proposal Attachment 6 – Benefits modelling.

### The incremental benefit of 1400 MW link capacity (Option 3 vs Option 2)

D202 Transpower analysis suggests that the operational benefits of increasing the HVDC link capacity to 1400 MW are primarily due to avoided deficit costs and savings in thermal operating costs and emissions.[321]

D203 Transpower notes that these benefits begin to accrue "around 2031 at the time when the Northwards capacity of the HVDC is assumed to increase to 1400MW for option 3".[322]

D204 Transpower explain that:[323]

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319 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 6 – Benefits modelling, Section 4.5.1, pp.30-31 available here.

320 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 6 – Benefits modelling, Section 4.5.1, p.31 available here.

321 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 6 – Benefits modelling, Section 4.5.2, p.33 available here.

322 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 6 – Benefits modelling, Section 4.5.2, p.33 available here.

323 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 6 – Benefits modelling, Section 4.5.2, p.33 available here.

The benefits are realised primarily during periods of high demand and low North Island wind generation. During these periods option 3 can provide 200 MW of additional firming to the North Island from South Island hydro. Without this, more expensive thermal generation would be dispatched, and in instances where there is insufficient generation capacity, deficit is incurred.

The variance between the scenarios reflects the different levels of North Island firm capacity available (including grid scale batteries) and differences in running costs for thermal firming generation. Note that the firm capacity available also varies with time due to the assumed retirement of existing thermal generation and the lumpy build of new generation and grid scale batteries in our expansion plans

D205 Transpower has also separately calculated the economic impact of the Pole 2 STOL scheme for the Environmental and Disruptive scenarios. Transpower state that without the overload scheme "system operational costs increase – particularly due to higher energy deficit costs – indicating that there are periods when the system is short on dispatchable capacity" presumably because higher generation reserves have to be held to account for a possible pole outage.[324]

D206 Transpower present analysis of the decrease in operational benefits without the Pole STOL investment in option 3. Transpower explains that "On average, not completing the Pole 2 overload upgrade results in a benefit reduction of approximately $45 million. Given that the Pole 2 overload project cost is approximately $13 million, the Pole 2 overload upgrade will deliver a net benefit of approximately $32 million."[325]

**Our observations of Transpower's investment test results**

D207 In reviewing Transpower's investment test application, we carried out our own analysis, taking a two-step approach. Firstly, we looked at the proposal and whether this passed the investment test.

D208 Secondly, we cross-checked Transpower's investment test application to satisfy ourselves that individual components of the proposal would deliver net electricity market benefits.

D209 In reviewing the economic analysis results in Transpower's proposal, we consider Transpower has taken a robust approach in applying the investment test, and that the costs and benefits have been reasonably calculated.

D210 Table D10 sets out the quantified cost and benefit investment test NPV results for the two key investment options Transpower considered in its proposal, namely option 2 and 3 with reference to Option1 (the base case).

324 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 6 – Benefits modelling, Appendix B, pp.45-46 available here.

325 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 6 – Benefits modelling, Appendix B, pp.45-46 available here.

**Table D10 Quantified costs and benefits ($ million in 2025 prices)[326]**

| Investment option | Total costs (A) | Total benefits (B) | Expected net market benefit (B-A) | Relative expected net market benefit |
|---|---|---|---|---|
| Option 1 – Base case | 475.2 | 0.0 | -475.2 | -3,226.9 |
| Option 2 – 1200 MW HVDC | 1,995.4 | 4,747.2 | 2,751.7 | 0.0 |
| Option 3 – 1400 MW HVDC | 2,107.2 | 4,925.2 | 2,818.0 | 66.3 |

D211 The proposed investment is to meet the economic limb of the GRS and must provide a positive electricity net market benefit. What the results in Table D10 demonstrate is that:

D211.1 the value to the New Zealand economy of the HVDC link is between $2,751.7 million ($ 2025) for the like-for-like 1200 MW capacity option (option 2), and $2,818.0 million ($ 2025) for the 1400 MW capacity option (option 3);

D211.2 Option 3 (the 1400 MW option) provides the highest quantified net electricity market benefit; and

D211.3 Option 3 provides a higher economic benefit of $66.3 million ($ 2025) when compared to option 2 and justifies the capacity of the HVDC link being increased to 1400 MW.

### Investment deferral of the 4th cable

D212 Transpower provided additional analysis for two deferral options – the fourth cable installed in 2035 and 2041. In both instances Transpower assumed that the fourth cable procurement occurred at the same time as the three replacement cables. Transpower explain that this is because:[327]

> Our market engagement indicates that future procurement of a single HVDC cable may be infeasible or highly risky due to limited global supply and increasing demand. There are few suppliers capable of producing cable compatible with our HVDC system and from our recent procurement experience the relatively short section of cable (40km) required will likely be unattractive to these suppliers and future availability cannot be guaranteed. To remove this risk, the fourth cable would still need to be ordered now, shipped to New Zealand, and stored – incurring additional costs for handling, storage infrastructure, and risk management.

326 *Transpower NZ Ltd*, USI Stage 1 MCP Attachment 4 – Application of the investment test, available here.

327 Transpower response to RFI012 – Fourth cable deferral economic analysis, p.2

D213 Transpower also noted that the cable termination stations would also need to be upgraded early to accept four cables, and that the near-term market benefits of 1400 MW capacity (ie, access to lower cost generation in the South Island) and the Pole 2 short-term overload capability would be unavailable until the fourth cable was installed. The longer the fourth cable is deferred, the lower the near-term benefits.

D214 Transpower provided investment test results showing that a 4th cable deferral may cost an additional $137.5 million ($ 2025) for the 2035 deferral to $148.6 million ($ 2025) for the 2041 deferral in the expected net market benefits. These investment test results are shown in Table D11.

**Table D11 4th cable deferral analysis ($ million 2025) using an average of all scenarios**[328]

| Option | Total cost PV | Total benefits PV | Expected net market benefit | Relative net market benefit |
|---|---|---|---|---|
| Proposal – 4 cables installed in 2031 | 2,123 | 4,925 | 2,802 | 0 |
| Deferral 2035 – 1200 MW in 2031 and 4th cable installed in 2035 | 2,240 | 4,905 | 2,664 | -138 |
| Deferral 2041 – 1200 MW in 2031 and 4th cable installed in 2041 | 2,208 | 4,861 | 2,653 | -149 |

D215 In summary what Transpower explained its deferral analysis demonstrates is that 4th cable deferral results in:

D215.1 a decrease in the present value of the total benefits – because the benefit of access to lower cost South Island generation and the Pole 2 short-term overload capability is delayed; and

D215.2 an increase in the present value of total costs – because of the significant cost associated with the additional cable installation remobilisation (note that as the 4th cable is deferred to 2041 the PV of the mobilisation cost decreases).

D216 We also asked Transpower, that if deferral was an economic consideration, how it would determine the timing of the fourth cable installation. The economic results indicate that the longer the fourth cable is deferred, the higher the relative net market cost. So the optimal timing of the 4th cable is when the three existing cables are installed.

328 Transpower response to RFI012 – Fourth cable deferral economic analysis, p.3.

D217 Transpower also carried out the 4th cable deferral analysis to test the effect of lower demand growth and how this would affect the economics of deferral with the results shown in Table D12.[329]

D218 Transpower used its lower growth Reference scenario which has a 30% lower demand growth than the Environmental scenario and a compounded demand growth of 1.1%.

**Table D12 4th cable deferral analysis using lower demand growth using the Reference scenario**

| Option | Total cost PV | Total benefits PV | Expected net market benefit | Relative net market benefit |
|---|---|---|---|---|
| Proposal – 4 cables installed in 2031 | 2,123 | 3,737 | 1,614 | 0 |
| Deferral 2035 – 1200 MW in 2031 and 4th cable installed in 2035 | 2,240 | 3,714 | 1,474 | -141 |
| Deferral 2041 – 1200 MW in 2031 and 4th cable installed in 2041 | 2,208 | 3,685 | 1,477 | -137 |

D219 The results in Table D12 demonstrate that the lower demand growth reduces net benefits of both deferral options and the proposal, while the relative benefits still favour an early installation of the 4th cable as remobilisation cost effects again dominate the NPV analysis.

D220 Following our review, we are satisfied that Transpower has adequately explained that a fourth cable deferral has a higher expected net market cost than what Transpower has proposed.

### Summary of our assessment of the investment test results

D221 We have carried out analysis to assess whether the HVDC Stage 1 MCP passes the investment test. Based on the evidence Transpower has provided and the analysis it has carried out, we are satisfied Transpower correctly applied the investment test and related Capex IM requirements in selecting option 3 as the proposed investment.

D222 However, Transpower's economic analysis results demonstrate that increasing HVDC link capacity to 1400 MW, while justified, is a marginal economic decision over the extended analysis timeframe.

329 Transpower response to RFI012 – Fourth cable deferral economic analysis (additional information), pp.5-7.

D223 We understand that there are uncertainties surrounding capital costs and where new generation will locate, and Transpower is working with the best information it has at present.

D224 Both options 2 and 3 will face the same cost uncertainties for the control system upgrade and whether the cable removal is a necessary cost that needs to be incurred. These are common costs that both options may incur so this will not affect the outcome of the relative difference in the benefits of these options.

D225 The main cost uncertainty when comparing options 2 and 3 will be if incremental cable capital costs are significantly higher than expected for the fourth cable and that this cost increase significantly lessens the relative benefit of option 3. This must be balanced against the significant market benefits of option 3 (see Table D9).

D226 On balance, we consider that the incremental cable capital cost increase above the calculated market benefits observed in Table D9 is unlikely to displace option 3 as the option with the most positive net market benefit. We note that the sensitivity analysis results in the next section demonstrate that this may be the case.

D227 Finally, we note that Transpower could probably reasonably make the case for using a lower discount rate for investments that promote renewables-based generation to meet climate change goals to more heavily weight the longer term benefit of facilitating these investments. A lower discount rate for these types of investment is likely to be arguable given the New Zealand Treasury advice on this has recently recommended that, for non-commercial long-term projects that include climate change initiatives, a discount rate of 2% should be considered.[330]

D228 A lower discount rate would place less emphasis on near-term capital costs and more weight on the longer-term benefits of facilitating renewables-based generation in the grid. Note that the sensitivity analysis results in Table D11 for the 3% discount rate show this effect on the benefit of Option 3 vs Option 2.

**The proposed investment is robust to sensitivity analysis**

D229 The Capex IM requires Transpower to perform a sensitivity analysis to test whether the proposed investment is robust to some key assumptions.[331] The Capex IM also lists the parameters that must be varied to assess whether the results of the investment test are robust to variations.[332] These parameters reflect the key assumptions that can have a significant impact on the investment test results.

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330 The Treasury's social discount rate, available here.

331 Capex IM, clause D7.

332 Capex IM, clause D7(1).

D230 There are two reasons sensitivity analysis is carried out. The first is to ensure that the proposed investment is robust to some of the key assumptions and passes the investment test. The second is whether the results of the investment test are robust to the selection of the proposed investment when compared to the investment options.

D231 Transpower considered a number of parameters in its core sensitivity analysis, including:[333]

D231.1 discount rates of 3% and 7%;

D231.2 capital cost sensitivities of +30% and -30% around central estimate;

D231.3 benefits increase (130% of base) and benefits decrease (70% of base);

D231.4 single EGDS scenarios namely, Reference, Environmental, Disruptive and Growth.

D232 The sensitivity analysis results are presented in Table D13.

**Table D13 Sensitivity analysis results ($ million in 2025 prices)[334]**

| Scenario | Option 1 (base case) | Option 2 (1200 MW HVDC) | Option 3 (1400 MW HVDC) | Option 3 vs Option 2 |
|---|---|---|---|---|
| Discount rate 3% | -573 | 5,113 | 5,263 | 150 |
| Discount rate 5% | -475 | 2,752 | 2,818 | 66 |
| Discount rate 7% | -398 | 1,354 | 1,372 | 18 |
| Capital cost +30% | -555 | 2,257 | 2,290 | 33 |
| Capital cost -30% | -395 | 3,246 | 3,346 | 100 |
| Benefits +30% | -475 | 4,176 | 4,296 | 120 |
| Benefits -30% | -475 | 1,328 | 1,340 | 12 |
| Reference scenario | -475 | 1,600 | 1,630 | 30 |
| Environmental scenario | -475 | 3,813 | 3,936 | 123 |
| Disruptive scenario | -475 | 2,735 | 2,829 | 94 |
| Growth scenario | -475 | 2,859 | 2,877 | 18 |

333 *Transpower NZ Ltd*, USI Stage 1 MCP Attachment 4 – Application of the investment test, Section 6, p.12, available here.

334 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 7 – Investment Test, Table 10, p.15, available here.

D233 We are satisfied the parameters Transpower used for its sensitivity analysis are reasonable. The results of Transpower's sensitivity analysis show that option 3 retains the highest expected net electricity market benefits for all sensitivity analysis parameters.

D234 We are satisfied Transpower's sensitivity analysis confirms that the proposed investment (Option 3) is robust to sensitivity analysis.