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COMMERCE COMMISSION NEW ZEALAND
Te Komihana Tauhokohoko

Transpower's HVDC Stage 1 major capex project proposal

Final decision - Reasons paper

18 June 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
28 April 2026	[2026] NZCC 9	Transpower Capital Expenditure Input Methodology (Major Capex Incentive Formula) Amendment Determination 2026

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Executive summary

X1 This paper sets out our (the Commerce Commission) review of, and final decision on, Transpower New Zealand Limited's (Transpower) HVDC Stage 1 major capex proposal (HVDC Stage 1 MCP) against the criteria in the Transpower Capital Expenditure Input Methodology Determination [2012] NZCC 2 (Capex IM).[1]

Transpower is seeking approval to replace existing HVDC assets and enhance HVDC capacity to 1400 MW

X2 Transpower is seeking approval to invest $1,138.6 million ($ nominal)[2] to replace existing HVDC transmission assets (three existing cables, the cable termination stations and the cable storage facility), enhance HVDC capability to 1400 MW (a fourth HVDC cable, Benmore filter bank), and introduce Pole 2 short-term overload capability.

X3 Transpower's proposed replacement expenditure is driven by the asset condition of the existing cables that are nearing end-of-life, seismic standards for the cable termination stations, and the need to relocate the cable storage facility. The enhancement component investments are driven by the economic benefit of increasing HVDC link capacity to 1400 MW and the ability of the proposed Pole 2 short-term overload (STOL) scheme to reduce reserves requirements in the wholesale electricity market.

X4 Transpower has explained that it needs to replace the HVDC control system and possibly remove the existing HVDC cables upon replacement. It has yet to fully scope and cost the control system upgrade and has deferred consideration of this into a Stage 2 application which we expect near the end of 2026.

X5 Transpower consulted on and updated the Ministry for Business, Innovation & Employment (MBIE) demand scenarios it used in the Net Zero Grid Pathways (NZGP) Stage 1 project, to derive peak and energy regional demand forecasts. Transpower did this after working closely with stakeholders.

X6 A pre-submission review was carried out by GHD Limited (GHD) to review aspects of the proposal such as investment need, investment need date, project costs, procurement and delivery risk. The GHD report conclusions resulted in Transpower staging the proposal and deferring a decision to submit the control system upgrade and cable removal to a later stage. The GHD report also assisted us in our review of the proposal.[3]

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1 The HVDC Stage 1 MCP process, proposal and decision documents are available here.

2 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)".

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

Our final decision is to approve Transpower's HVDC Stage 1 MCP

X7 Following our review, our final decision is to approve Transpower's HVDC Stage 1 MCP proposal. Transpower has demonstrated that the proposed investment provides the highest electricity net market benefit when compared to the investment options considered and is consistent with the requirements of the Capex IM.

X8 We are satisfied that Transpower delivering the HVDC Stage 1 MCP project will promote the purpose of Part 4 of the Commerce Act 1986 (the Act). Our decision to approve the HVDC Stage 1 MCP proposal will:

X8.1 provide Transpower with incentives to invest in enhancing the HVDC grid; and

X8.2 ensure there is sufficient HVDC transmission capacity to ensure lower cost generation in the South Island has access to meet North Island demand.

Our major capex allowance, exempt major capex and incentive rate final decision

X9 In reaching our final decision to approve Transpower's proposal, the Capex IM requires us to determine the:[4]

X9.1 major capex allowance;[5]

X9.2 exempt major capex;[6] and

X9.3 major capex incentive rate.[7]

X10 Our HVDC Stage 1 MCP final decision is to:

X10.1 set a major capex allowance (MCA) of $1,138.6 million ($ nominal);

X10.2 set the capital cost contingency risk component of $140.1 million ($ 2025) as exempt major capex; and

X10.3 set an incentive rate of 15% that will apply to all major capex that is not exempt major capex.

4 Capex IM, clause 3.3.5(7) and Schedule C.

5 Under Capex IM, clause 1.1.5(2), 'major capex allowance' means the amount of major capex we approve in relation to an approved MCP.

6 Under Capex IM, clause 1.1.5(2), 'exempt major capex' means the amount of the MCA to which the major capex incentive rate does not apply which may be expressed by reference to a category of expenditure within the MCP, as we determine under clause 3.3.5(7) of Capex IM.

7 Under Capex IM, clause 1.1.5(2), 'major capex incentive rate' means 15% or an alternative rate we specify in respect of an approved MCP.

Chapter 1 Introduction

Purpose of this chapter

1.1 The purpose of this paper is to:

1.1.1 explain our final decision to approve Transpower's HVDC Stage 1 MCP; and

1.1.2 review submissions from interested parties on our draft decision, which has informed our final decision to approve the application.

Structure of this paper and attachments

1.2 The body of this paper sets out:

1.2.1 the background to Transpower's HVDC Stage 1 MCP proposal;

1.2.2 a summary of submissions and cross-submissions on our draft decision and our response to those submissions; and

1.2.3 our final decision to approve Transpower's HVDC Stage 1 MCP proposal.

1.3 Attachments A-D set out the decision-making framework, analysis, reasons, and Capex IM criteria underpinning our final decision. Specifically:

1.3.1 Attachment A sets out our decision-making framework under the Capex IM, and the evaluation criteria under the Capex IM, comprising general criteria,[8] specific criteria,[9] and the investment test;[10]

1.3.2 Attachment B provides our evaluation of the HVDC Stage 1 MCP proposal against the Capex IM general criteria;

1.3.3 Attachment C provides our evaluation of the HVDC Stage 1 MCP proposal against the Capex IM specific criteria; and

1.3.4 Attachment D provides our evaluation of Transpower's application of the Capex IM investment test.

Our role in reviewing major capex project proposals

1.4 We (the Commerce Commission) regulate Transpower's revenues under Part 4 of the Commerce Act. We set a general revenue allowance for each regulatory period via Transpower's individual price-quality path.

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8 Capex IM, Part 6.
9 Capex IM, Schedule C.
10 Capex IM, Schedule D.

1.5 Transpower must apply separately to us for approval of its MCP proposals aimed at enhancing or developing the transmission grid. We then review Transpower's MCP application against the Capex IM criteria to ensure that the expenditure is justified and in the long-term interest of consumers.

Regulatory approval process to date

1.6 A summary of our regulatory approval process for the HVDC Stage 1 MCP proposal prior to this decision is as follows:

1.6.1 On 23 April 2025, Transpower notified us of its plan to develop an MCP proposal and that the HVDC Stage 1 MCP would be a staged MCP (NOI).[11]

1.6.2 On 22 May 2025, we acknowledged Transpower's 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 non-transmission solutions (NTS).[12,13]

1.6.3 In our 22 May 2025 NOI response to Transpower we included the requirement that Transpower only needed to carry out a short-list consultation.[14]

1.6.4 Transpower consulted on its short-list of investment options (short-list consultation) between May and June 2025.[15]

1.6.5 On 4 September 2025, Transpower submitted its proposal to us for our approval.[16]

1.6.6 We published our draft decision on 1 April 2026 and received submissions and cross-submissions on that draft decision, on 29 April 2026 and 13 May 2026, respectively.[17]

1.6.7 Before making our final decision, we considered submitters' views on our draft decision, which we then incorporated into our decision-making process.

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11 *Transpower New Zealand Ltd*, Letter of Notification under clause 3.3.1(1) of the Capex IM, available here.

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

13 Capex IM, clause 8.1.3(2)(b).

14 Capex IM, clause 8.1.3(2)(b).

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

16 *Transpower New Zealand Ltd*, Application to the Commerce Commission for the HVDC Stage 1 MCP, available here.

17 *Commerce Commission*, Transpower's HVDC Stage 1 MCP draft decision - reasons paper, 1 April 2026, available here.

Chapter 2 Overview and background

Purpose of this chapter

2.1 In this chapter we provide a background on Transpower's HVDC Stage 1 MCP, and outline:

2.1.1 what major capex projects are under the Capex IM; and

2.1.2 the content of and background to the proposal.

Major capex projects under the Capex IM

2.2 A 'major capex project' is defined in the Capex IM to mean a project of major capex undertaken to address or enable a specific investment need to be met, which may be either, or both, a transmission investment or NTS.[18]

2.3 Major capex covers capital expenditure for large individual transmission grid enhancement projects that, given their nature and magnitude, warrant our individual scrutiny and public consultation.[19] Specifically, 'major capex' means expenditure that is:[20]

2.3.1 incurred to meet the grid reliability standards (GRS) or provide a 'net electricity market benefit';[21]

2.3.2 forecast to have an aggregate capital cost exceeding the base capex threshold of $30 million;[22]

2.3.3 not incurred in relation to asset replacement, asset refurbishment, business support or information system, and technology assets; and

2.3.4 not funded under a new investment contract.

2.4 Transpower is required to submit a major capex project proposal to us when it seeks approval for a major capex project.[23]

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18 Capex IM, clause 1.1.5(2).

19 *Commerce Commission*, Transpower Capex Input Methodology Review – Decisions and reasons (29 March 2018) para 54, available here.

20 Capex IM, clause 1.1.5(2).

21 Capex IM, clause 1.1.5(2), the GRS are as defined under Schedule 12.2 under the Electricity Industry Participation Code 2010 (**Code**).

22 From 1 April 2025, the revised base capex threshold is $30 million. Since the MCP was first notified (5 April 2023), prior to the revised capex threshold coming into effect, the forecast capex must exceed $20 million to be classified as major capex.

23 Capex IM, clause 3.3.3(2), and the definitions of 'major capex' and 'base capex threshold' under clause 1.1.5(2). Note that in the 2023 IM Review we amended the base capex threshold to $30 million which took effect on 1 April 2025.

2.5 The Capex IM also sets out the information that Transpower needs to provide in the MCP, and the associated certification of the information it provides.[24] The Chief Executive Officer (CEO) of Transpower must certify that the information provided accurately represents Transpower's operations. The CEO certification must also state the proposed investment was approved according to Transpower's director and management approval policies.[25]

2.6 Transpower may submit an MCP to us at any time during a regulatory period.[26]

What happens if we approve a project

2.7 If we approve a project, Transpower may, after commissioning the relevant assets, include the actual costs of the assets in its regulatory asset base.[27] Transpower may then recover those costs under its individual price-quality path (IPP), as transmission charges allocated to its customers, according to the transmission pricing methodology (TPM).[28,29]

2.8 Transpower provided a table of estimated increases in transmission charges for each customer, from the expenditure relating to the proposal.[30,31]

Background to the HVDC Stage 1 MCP proposal

2.9 Transpower proposes upgrading existing HVDC transmission assets as well as adding new HVDC assets to increase HVDC link capacity from 1200 MW to 1400 MW. Transpower also proposes upgrading or replacing assets due to earthquake related issues (the cable termination station) and replacing assets that are no longer fit for purpose and cannot be accessed when needed (the spare cable storage facility).

2.10 The HVDC capacity enhancement component involves installing a fourth cable to raise link capacity from 1200 MW to 1400 MW to access the full capacity of the converter stations. An additional filter bank is also required at Benmore to manage harmonic levels at high direct current (DC) transfers.

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24 Capex IM, clause 7.4.1 and Schedule G.
25 Capex IM, clause 9.2.1.
26 Capex IM, clause 9.2.1.
27 *Commerce Commission*, Transpower Input Methodologies Determination 2010 [2012] NZCC 17, clause 2.2.3(2)(f).
28 *Commerce Commission*, 2025-2030 Transpower individual price-quality path (RCP4), Individual Price Path (IPP) Determination clause 8, available here.
29 The TPM is the methodology by which Transpower prices its transmission services developed in accordance with subpart 4 of Part 12 of the Electricity Industry Participation Code 2010 (Code) and specified in Schedule 12.4 of the Code.
30 Capex IM, clause 7.5.1(1)(c).
31 *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 9 – TPM and Indicative Pricing Impacts, available here.

2.11 Transpower also proposes installing a Pole 2 short-term overload scheme to allow HVDC link overload capability when a pole outage occurs. This investment reduces the amount of reserve cover needed in the electricity market and will have the effect of lowering overall wholesale electricity market prices.

2.12 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.

2.13 As the cables are approaching end-of-life, Transpower has been developing cable asset health models and has increased its condition assessment focus. Transpower has assessed that cable condition varies along the cable length and has forecast that the first year for replacement intervention is in 2032 for two cables, and 2035 for the third cable.

2.14 Due to international demand for HVDC cables and associated equipment, Transpower is seeking early approval for this MCP proposal to ensure that it has the cable assets delivered and installed by 2031.

2.15 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."[32]

2.16 As part of the cable replacement contract, Transpower is purchasing 10km of spare cable to enable it to repair faults if required. For this, a new dedicated cable storage facility is necessary.

2.17 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.

2.18 Transpower is seeking a MCA of $1,138.6 million ($ nominal) and work will commence as soon as funding is approved, with a forecast commissioning date of 31 December 2031 for the final investment in the proposal.[33]

2.19 This proposal is Stage 1 of a two-stage proposal, and we only consider the Stage 1 works in this final decision. The Stage 2 works will involve replacement of the existing HVDC control system and possibly removal of the existing HVDC cables (although it is yet to be determined if this is required). Transpower has signalled that it is likely to submit a Stage 2 application to us late in 2026.

2.20 Figure 2.1 shows the map of the transmission network and the HVDC link connection between Benmore and Haywards substations.

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

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

Figure 2.1 Overview of the transmission network showing the HVDC link[34]

2.21 Table 2.1 sets out the short-list investment options Transpower considered when it applied the Capex IM investment test. The proposed investment in the HVDC Stage 1 MCP is option 3 and Table 2.2, the expected costs in 2025 $'s for the Stage 1 and Stage 2 investments.

[34] *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 2 – Need, demand and generation scenarios, Figure 1, p.2, available here.

Table 2.1 The short-list investment options considered[35]

Option	Description of transmission developments
1	**Base case option** The HVDC submarine cables, control systems and termination stations are not upgraded. Over time, as components fail, the HVDC link will be decommissioned.
2	**1200MW option** 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	**1400MW option** Replacement of the three submarine cables with four submarine cables to support 1400 MW north transfer 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.

Table 2.2 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**	

[35] *Transpower NZ Ltd*, HVDC Stage 1 MCP Attachment 4 – Short list of investment options, Table 2, p.14, available here.

Chapter 3 Our final decision is to approve Transpower's proposal

Purpose of this chapter

3.1 This chapter explains our decision settings for the approval of Transpower's HVDC Stage 1 MCP proposal.

3.2 In approving Transpower's proposal, we evaluated and determined the:[36]

3.2.1 MCA;

3.2.2 exempt major capex; and

3.2.3 major capex incentive rate.

3.3 We also evaluated the following components proposed by Transpower:[37]

3.3.1 the major capex project outputs;

3.3.2 the approval expiry date; and

3.3.3 the commissioning date assumption.

3.4 This section summarises our evaluation and determination of these components. Our assessment of Transpower's proposal against the Capex IM criteria is set out in more detail in Attachments B to D.

We are satisfied that the project meets the evaluation criteria

3.5 Having completed our evaluation we are satisfied that the proposal meets the:

3.5.1 general Capex IM evaluation criteria as described in Attachment B;

3.5.2 specific Capex IM criteria as described in Attachment C; and

3.5.3 Capex IM investment test as described in Attachment D.

3.6 We are satisfied the information, assumptions, and supporting analysis provided by Transpower satisfy the Capex IM general and specific evaluation criteria, and that the proposal meets the requirements of the investment test.

[36] Capex IM, clause 3.3.5(7) and Schedule C.
[37] Capex IM, clause 3.3.5(6) and Schedule C.

3.7 We are satisfied that Transpower has demonstrated the need to invest to replace the existing cables, cable termination stations, the cable storage facility. We also agree that installing a fourth cable, adding an additional filter at Benmore, and introducing the Pole 2 short-term overload capability provides the highest benefit when compared to the other investment options Transpower considered.

3.8 The proposed investment is to meet the economic limb of the GRS and must provide the highest positive electricity net market benefit. Based on the assumptions made Transpower has demonstrated that:[38]

3.8.1 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);

3.8.2 Option 3 (the 1400 MW four cable option) provides the highest quantified net electricity market benefit and is robust to sensitivity analysis; and

3.8.3 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.

3.9 Transpower investigated potential investment options to meet the investment need, consulted with customers, and identified the option that delivers the highest expected electricity net market benefit.[39]

3.10 We consider the proposed investment will meet the Part 4 purpose as it will ensure North Island demand has continued access to lower cost South Island generation, and that this provides a long-term benefit to consumers.

3.11 In reaching our decision, we carried out investigations in a number of key areas. These include assessing:

3.11.1 the findings of the GHD Limited (GHD) independent expert review;[40]

3.11.2 the cable replacement need date and asset health models it has used to identify this need date;

3.11.3 the fourth cable deferral option economic analysis, which was an alternative investment option raised by Vector in its short-list consultation submission;

3.11.4 Transpower's generation development assumptions raised by submitters in the short-list consultation submissions.

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38 The stated values are net present values discounted at 5% to 2025.

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

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

3.11.5 how the 2019 Electricity Demand and Generation Scenarios (EDGS) update compared with the most recent 2024 EDGS which was not used in the proposal scenario analysis;

3.11.6 the capital cost assumptions Transpower has made and how it calculated its cost contingencies; and

3.11.7 Transpower's historical cost estimation accuracy for major projects and how this has influenced our decision to agree to set an incentive rate of 15%.

3.12 We summarise our findings below and expand further on them in Attachments B to D,

The GHD independent expert review

3.13 Prior to Transpower submitting the HVDC Stage 1 MCP to us, it engaged GHD to carry out a pre-submission independent review of the proposal.

3.14 We 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) reset proposals.

3.15 GHD tested many aspects of the proposal that included technical need, project cost estimates and procurement issues that may affect delivery risk. We used GHD's conclusions to help direct our review of the key matters in the proposal.

3.16 GHD concluded that, overall, the proposed cable investments align with good industry practice based on asset health considerations, with the proposed 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."[41]

3.17 GHD assessed that the existing cable termination stations currently do not meet current seismic requirements of Transpower's policy and design codes which are aligned to the New Zealand standards.

3.18 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. [42]

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

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

3.19 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".[43] Transpower design principles assign the IL4 threshold to major electricity substations, control centres, and other key infrastructure like the HVDC link.

3.20 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.

3.21 GHD concluded that Transpower's plan to build new termination stations will minimise outage requirements, because remediating the existing structures will likely result in lengthy outages. As a result, GHD concluded that the remediation option was not economically feasible.[44]

3.22 For the existing cable removal, GHD noted 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. This conclusion resulted in Transpower deferring a decision on this to a Stage 2 application along with the control system replacement, so Transpower can refine the project scope and costs.

3.23 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.

3.24 GHD agreed that the Benmore filters and Pole 2 short-term overload scheme are justifiable investments.

3.25 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.

The need for cable replacement

3.26 The cable replacement investment need is driven by the existing HVDC cables reaching end-of-life, based on condition assessments supported by asset health models.

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

44 *GHD*, Independent Review - HVDC Link Upgrade Programme, p.iv, and Section 5.1, pp.30-32, available here.

3.27 To assess cable replacement need, we focussed our review on Transpower's HVDC cable asset health modelling process and outcomes as well as assessing the GHD report conclusions. We sought more detail about how Transpower had identified the cable replacement need dates.

3.28 While the decision to replace the cables by the early 2030's is a model-driven risk-based decision, Transpower notes that it has already had to repair a cable fault in 2004, which took 6 months.[45] The risk of faults on the existing cables is only set to increase, and loss of HVDC transfer capability will have a significant economic impact due to the resulting increased wholesale electricity market prices.

3.29 Following our review, we conclude that Transpower has made the case for replacing the existing cables and that a reasonable need date has been demonstrated. This technical decision to replace the cables is bolstered by the conclusions of the GHD expert review.

3.30 Transpower has also explained that there are cable procurement issues and that cable production capacity has to be reserved with manufacturers well ahead of need to ensure timely replacement. Global demand for HVDC cables has necessitated this approach, and we support Transpower's strategy.

The fourth cable deferral option

3.31 We sought further information from Transpower about whether deferring the installation of a fourth cable would provide a higher benefit than the proposal to install it at the same time as the existing three cables are replaced (the proposal).

3.32 In its short-list submission Vector suggested that the 4th cable could be deferred as it would retain optionality and that it may not be necessary if "North Island demand or renewable development grows more slowly than Transpower's 'Growth' or 'Environmental' scenarios".[46]

3.33 Transpower provided additional analysis during our review process, testing two deferral options – the fourth cable installed in 2035 and 2041.[47] Transpower demonstrated that installing a fourth cable at the same time as it replaces the three existing cables provides a higher net market benefit than deferral.

3.34 Transpower's investment test results show that a fourth cable deferral may cost, in a net market benefit sense, an additional $137.5 million ($ 2025) for the 2035 deferral, and $148.6 million ($ 2025) for the 2041 deferral.[48]

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45 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.

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

47 In both instances Transpower assumed that the fourth cable procurement occurred at the same time as the three replacement cables. Transpower explained that this was because of future procurement considerations with the manufacturer and its potential unwillingness to reserve capacity for a single cable.

48 Transpower response to RFI012 – Fourth cable deferral economic analysis, p.3.

3.35 The economic results indicate that the longer the fourth cable is deferred, the higher the relative net market cost. These deferral analysis results are shown below in Table 3.1.

Table 3.1 4th cable deferral analysis ($ million 2025)[49]

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

3.36 Transpower explained that its deferral analysis demonstrates is that 4th cable deferral results in:[50]

3.36.1 a decrease in the present value of the total benefits – because the benefits of accessing lower cost South Island generation and Pole 2 short-term overload capability are delayed; and

3.36.2 an increase in the present value of total costs – because of the significant cost associated with the additional cable installation remobilisation costs (note that as the 4th cable is deferred to 2041 the present value of mobilisation costs decrease).

3.37 We 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, and on this basis Transpower argues that the optimal timing for the fourth cable is when the three replacement cables are installed.[51]

3.38 Transpower also carried a 4th cable deferral analysis to test the effect of lower demand growth. The analysis results are shown in Table 3.2. Transpower used its lower growth reference scenario which has a 30% lower demand growth than the environmental scenario, with a compounded demand growth rate of 1.1%.[52]

49 Transpower response to RFI012 – Fourth cable deferral economic analysis, p.3.
50 Transpower response to RFI012 – Fourth cable deferral economic analysis (additional information)
51 Transpower response to RFI012 – Fourth cable deferral economic analysis, p.3.
52 Transpower's email of 4 March 2026 response in response to our query of 27 February 2026.

3.39 The results in Table 3.2 demonstrate that the lower demand growth reduces the overall net benefits of both deferral options and the proposal, while the relative benefits still favour an early installation of the 4th cable.

Table 3.2 4th cable deferral analysis using lower demand growth[53]

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

3.40 We questioned why the overall benefits reduced but the relative benefits of deferral were similar to the base case deferral results in Table 3.1. Transpower responded that the deferral PV analysis is dominated by the capital costs of cable installation remobilisation, a cost that is incurred only once in the proposal but twice in the deferral options.[54,55]

3.41 Following our review, we are satisfied that Transpower has demonstrated that deferring installation of a fourth cable is less economically favourable than the installation of a 4th HVDC cable at the same time as it proposes to replace the existing three cables.

The use of the 2019 EDGS and generation assumptions

3.42 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.

3.43 This HVDC Stage 1 MCP is an upgrade to meet the economic limb of the GRS so the benefits of the 1400 MW upgrade beyond the existing 1200 MW HVDC capacity need to outweigh the costs. As such, the generation scenario assumptions will have a significant economic impact.

3.44 In its consultation, Transpower explained that it used an update to the 2019 EDGS published by the MBIE rather than the 2024 EDGS.

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53 Transpower's email of 4 March 2026 response in response to our query of 27 February 2026.
54 Transpower response to RFI012 – Fourth cable deferral economic analysis (additional information)
55 While there was a small reduction in accessing the benefits of increased HVDC capacity due to lower demand growth, the PV analysis is dominated by the cost of cable installation re-mobilisation.

3.45 Transpower also received consultation submissions suggesting that the 2019 EDGS assumptions were out of date, and some submitters (Meridian and Fonterra) provided specific generation assumption data for Transpower to consider.

3.46 We tested Transpower on its use of the 2019 EDGS update and how it had addressed the specific generation assumption information it received in its consultation, as well as its modelling of potential new solar plant in the South Island.

3.47 Transpower defended its use of the 2019 EDGS update 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."[56]

3.48 In its proposal, Transpower discusses 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.

3.49 Following our review, we are satisfied that Transpower has reasonably explained the specific consultation questions and why it has chosen to update the 2019 EDGS rather than use the 2024 EDGS.

Capital cost estimates and contingent amounts

3.50 A key focus of our review was to test Transpower's capital cost estimates and cost contingencies given that HVDC assets and related investments (such as the Pole 2 STOL and Benmore filter) are not typical investments Transpower makes.

3.51 Many of 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 (particularly cable installation costs), 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 have taken these cost uncertainties into account in our application of the project incentive scheme.

3.52 We discuss our capital cost review and how we reviewed the cost contingencies more fully in Attachment D, which has informed our decision on the exempt major capex setting.

[56] Transpower response to RFI004 – Demand and generation scenarios, p.3.

What we heard in draft decision submissions

Consultation submissions and cross-submissions on our HVDC Stage 1 MCP draft decision

3.53 We received three submissions on our draft decision from Meridian Energy Limited (Meridian), New Zealand Steel Limited (NZ Steel), and Phillip D'Ath,[57] and two cross-submissions, from Transpower and the Major Electricity Users Group (MEUG), on those submissions.[58]

3.54 We categorised the key matters raised in submissions and cross-submissions as follows:

3.54.1 proposal support;

3.54.2 MCP decision settings;

3.54.3 decision to increase HVDC capacity to 1400MW;

3.54.4 cable termination station resilience to outages; and

3.54.5 pricing information timing.

3.55 We summarise the submissions and cross-submissions below and discuss how we have had regard to them in making our final decision.

3.56 The Attachments to this paper, which set out the focussed analysis and reasons underpinning our decision, draw on points raised in submissions and cross-submissions where appropriate.

Our draft decision to approve the HVDC Stage 1 MCP

3.57 In their draft decision submissions, Meridian and Phillip D'Ath supported the draft decision.

3.58 Meridian stated that it supported the project in principle, and while it had not "assessed in detail the modelling of benefits undertaken by Transpower, or carried out its own modelling", it considered the finding that "Option 3 (the 1400 MW four cable option) would provide the highest net electricity market benefit and economic benefit is unsurprising" and consistent with its own expectations.[59]

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57 *Meridian,* submission on HVDC Stage 1 MCP draft decision, available here, *NZ Steel,* submission on HVDC Stage 1 MCP draft decision, available here, *Phillip D'Ath,* submission on HVDC Stage 1 MCP draft decision, available here.

58 *Transpower NZ Ltd, cross*-submission on HVDC Stage 1 MCP draft decision, available here.

59 *Meridian,* submission on HVDC Stage 1 MCP draft decision, p.1, available here.

3.59 Phillip D'Ath "strongly supports the proposal" because replacing the three ageing Cook Strait cables with four new ones, plus new termination stations, raises inter-island capacity from 1,200 MW to 1,400 MW. This improves reliability, reduces blackout and price spike risks, and delivers $66.3 million net market benefit" and that the additional cable would enable "better sharing of renewable generation between islands, keeping long-term prices down for domestic consumers".[60]

3.60 While not fully agreeing with the timing of the HVDC capacity increase to 1400MW, NZ Steel submitted that it commended Transpower for "front-footing replacement of essential and ageing infrastructure".[61]

3.61 In its cross-submission, MEUG supported the proposal to raise HVDC capacity to 1400 MW but agreed with NZ Steel that affordability was becoming a concern for electricity users, noting that New Zealand is "on a pathway to greater electrification, but there is a real risk that demand could be subdued if electricity becomes too unaffordable" and that "deindustrialisation" due to price increases, is a real possibility.[62]

3.62 MEUG cross-submitted that it agreed with the NZ Steel submission about "anticipatory investments" and how the "costs will fall on consumers of the day, not necessarily the beneficiaries over time (both current and future generations)".[63]

3.63 We are aware that price increases are a concern and that this is due to wholesale market price increases, and increased investment in the transmission and distribution sectors to meet forecast electrification demand. Additionally, we know that asset costs have risen globally as global demand for these has risen to meet a global shift away from fossil fuels in industry. MEUG's view is that continued electricity price increases may have a cooling effect on forecast demand.

3.64 However, the majority of this MCP proposal is expenditure related to the replacement of existing assets, which Transpower has demonstrated in its proposal, provide significant benefit to the New Zealand economy. We are satisfied that without the HVDC link, electricity prices would be much higher, especially in the North Island.

3.65 We also note that Transpower has tested lower demand increase effects on the need for the HVDC capacity increase investment, and that even with a reduced demand increase assumption, the additional HVDC capacity is demonstrably beneficial to consumers in a net market benefit sense.

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60 *Phillip D'Ath,* submission on HVDC Stage 1 MCP draft decision, p.1, available here.
61 *NZ Steel,* submission on HVDC Stage 1 MCP draft decision, p.1, available here.
62 *MEUG, cross*-submission on HVDC Stage 1 MCP draft decision, p.2, available here.
63 *MEUG, cross*-submission on HVDC Stage 1 MCP draft decision, p.2, available here.

MCP decision settings

3.66 Phillip D'Ath agreed with the draft decision to include "$140.1 million contingency as exempt major capex and 15% incentive rate"[64], while Meridian stated that "contingent costs (such as weather-related cable installation costs and cable route uncertainty) should be exempt major capex and that Transpower should not be rewarded via the incentive mechanism for not spending a contingent amount".[65] In its cross-submission MEUG agreed with Meridian's view on how contingent costs should be treated.[66]

3.67 Meridian strongly supported the draft decision to "retain the P30/P70 cost estimate deadband on the incentive mechanism and retain the exempt major capex mechanism",[67] and in its cross-submission, MEUG supported the draft decisions settings for the:[68]

3.67.1 MCA of $1,138.6 million ($ nominal);

3.67.2 a capital cost contingency risk component of $140.1 million ($ 2025) as exempt major capex; and

3.67.3 an incentive rate of 15% that will apply to all major capex that is not exempt major capex.

Decision to increase HVDC capacity to 1400MW

3.68 While NZ Steel agreed with the need for the cable replacement work, it questioned the timing of the investment to raise HVDC capacity to 1400MW and the impact early capacity investment would have on the Transpower Regulatory Asset Base (RAB) and subsequent consumer charges.[69]

3.69 In NZ Steel's opinion, our draft decision would "see the risk and cost of this coming to today's consumers when the benefit, if at all, may be a decade or more beyond the spend" and that once the investment is made an enters the RAB, Transpower can charge consumers for it, even if the capacity is unused.[70]

3.70 NZ Steel hold the view that "anticipatory investment should be financed by Transpower and carried at the risk of the shareholder until any benefits flow to the consumers at that time" and be "carried on the Transpower balance sheet outside the RAB" and that this opens a wider debate that generators should bear the cost of "transporting their 'product' to the consumer". NZ Steel does accept, though, that this is an Electricity Authority/TPM matter.[71]

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64 *Phillip D'Ath,* submission on HVDC Stage 1 MCP draft decision, p.1, available here.
65 *Meridian,* submission on HVDC Stage 1 MCP draft decision, p.1, available here.
66 *MEUG, cross*-submission on HVDC Stage 1 MCP draft decision, p.1, available here.
67 *Meridian,* submission on HVDC Stage 1 MCP draft decision, p.1, available here.
68 *MEUG, cross*-submission on HVDC Stage 1 MCP draft decision, p.1, available here.
69 *NZ Steel,* submission on HVDC Stage 1 MCP draft decision, p.1, available here.
70 *NZ Steel,* submission on HVDC Stage 1 MCP draft decision, p.1, available here.
71 *NZ Steel,* submission on HVDC Stage 1 MCP draft decision, p.1, available here.

3.71 While NZ Steel had no comment on the majority of the proposed replacement work, it asked us to look closely at alternative options of where "the risk and cost lies, in particular relating to the anticipatory investment regarding the 1200-1400MW capacity increase".[72]

3.72 In its cross-submission, Transpower noted that there are a number of benefits that it has identified that are not only driven by demand growth, including:[73]

3.72.1 retirement of thermal generation in the 2030s;

3.72.2 expanding North Island wind generation;

3.72.3 enabling South Island hydro to provide firming and displace higher-cost thermal generation; and

3.72.4 freeing up reserve generation by the increased HVDC self-cover.

3.73 Transpower reiterates that deferral of the fourth cable installation would add additional costs to consumers, and that its analysis demonstrates that there is clear benefits in releasing full HVDC link converter capacity to 1400MW at the same time as it replaces the three existing cables noting that:[74]

> Deferring the fourth cable to either 2035 or 2041 requires a separate future installation campaign, which introduces additional mobilisation costs and reduces the efficiencies associated with installing cables together. Remobilisation costs to lay the fourth cable are expected to be significant, in excess of $260m. While both deferral options incur additional mobilisation costs, the 2041 option has a lower PV cost than the 2035 option because those additional remobilisation costs occur later in the analysis period and are therefore more heavily discounted

3.74 As noted in the Attachment D analysis, there are electricity market reserve benefits associated with 1400MW HVDC capacity that occur as soon as it is available. These are the reserve benefits, enabled by the increased capacity and the Pole 2 short-term overload (STOL) functionality, and are approximately half the total benefit Transpower has calculated for the 1400MW capacity option. We are satisfied that these benefits occur as soon as the additional capacity and Pole 2 STOL functionality is installed.

Cable termination station resilience to outages

3.75 Meridian reiterated its concern about outages caused by salt spray buildup on HVDC insulators that it states have caused outages and "significant market impacts and costs".[75]

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72 *NZ Steel,* submission on HVDC Stage 1 MCP draft decision, p.2, available here.
73 *Transpower NZ Ltd, cross*-submission on HVDC Stage 1 MCP draft decision, p.1, available here.
74 *Transpower NZ Ltd, cross*-submission on HVDC Stage 1 MCP draft decision, p.1, available here.
75 *Meridian,* submission on HVDC Stage 1 MCP draft decision, p.2, available here.

3.76 Meridian notes that the Transpower plan is to consider the "use of more pollution-resistant equipment, including longer and larger HV bushings, application of anti-salt buildup coatings, permanent washdown facilities, and a seaward-facing screen to protect roof bushings". Meridian looked forward to "clarification on whether these measures would mitigate the outage risk and how the costs and benefits compare to any potential building sites further inland".[76]

3.77 Meridian suggests that the final design of the termination station should consider options that are resilient to climate change and increased likelihood of storm events concluding that "once a decision is made on the design and location of the termination station, the market should be updated so there is a common understanding of whether these outage risks remain."[77]

3.78 Transpower, in its cross-submission, states that its current termination station design "locates the new termination station adjacent to the existing buildings, on a site that Transpower already owns and has designated for this purpose" and that it has "now assessed the possibility of inland sites and have ruled them out due to constrained typography, fault line presence as well as the significant cost and time delays."[78]

3.79 Transpower notes that while termination station location will effectively be the same as the existing site, it will be "further investigating building orientation, bushing design and pollution resistance and washing systems", and that as it progresses to a more detailed design, it will "assess whether any additional costs around building design to avoid salt spray related outages are net beneficial."[79]

3.80 We consider that Transpower has reasonably considered alternatives for the cable termination station location and is aware of the salt spray induced outage potential, noting that Transpower is incentivised to meet HVDC availability quality standards, set in each five-year revenue reset.

Pricing information timing

3.81 In its submission, Meridian was critical of the timing of the transmission pricing information, stating that Transpower's plan to consult on pricing impact after the approval of the MCP was "unacceptable".[80] In its cross-submission, MEUG agreed with Meridian's views on the timing of pricing information.[81]

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76 *Meridian,* submission on HVDC Stage 1 MCP draft decision, p.2, available here.
77 *Meridian,* submission on HVDC Stage 1 MCP draft decision, p.2, available here.
78 *Transpower NZ Ltd, cross*-submission on HVDC Stage 1 MCP draft decision, p.2, available here.
79 *Transpower NZ Ltd, cross*-submission on HVDC Stage 1 MCP draft decision, p.2, available here.
80 *Meridian,* submission on HVDC Stage 1 MCP draft decision, p.2, available here.
81 *MEUG, cross*-submission on HVDC Stage 1 MCP draft decision, p.2, available here.

3.82 In its cross-submission, Transpower responded to Meridian, stating that its short-list consultation material and proposal included information that provided "indicative pricings" based on " meter data from a capacity measurement period that is the closest complete (capacity measurement period (CMP) from September to August) to the timing of the proposal."[82]

3.83 Transpower concedes that, while these pricing estimates are not the final Benefit Based Investment (BBI) cost allocations required by the TPM administered by the Electricity Authority (EA), they are "a reasonable indication of the distribution of net private benefits from the HVDC investment as they use the modelling inputs and assumptions for the proposal."[83]

3.84 Transpower further states that its interpretation of the TPM requirements means that it is required to consult on the BBI cost allocations after an MCP has been approved, noting that "meter data used for indicative allocations under the Capex IM may differ from the data used for final allocations under the TPM. As a result, allocations for the purpose of meeting the Capex IM remain indicative only."[84]

3.85 While not a consideration in our MCP decision, cost allocation information timing is a matter for submitters to raise with the EA.

Our final decision settings

Major capex allowance

3.86 Our final decision is to set a MCA of $1,138.6 million ($ nominal) for the HVDC Stage 1 MCP proposal. The MCA we are setting is based on Transpower's base cost estimate, plus the 50th percentile of uncertainties. Transpower also provided P30 and P70 cost estimates for use in the incentive scheme.

3.87 Transpower used manufacturer quotes, in-house designs, external consulting reports and its Transpower Enterprise Estimating System (TEES) cost estimation framework, to estimate the HVDC Stage 1 MCP and modelled project capital costs.

3.88 We tested Transpower's costs and cost estimation processes and are satisfied these are reasonable. While there is still cost uncertainty about some project costs, such as the cable asset and installation final costs, we understand that Transpower is using the best information it has at this stage of the project.

3.89 Our MCA final decision for the HVDC Stage 1 MCP set out in Table 3.1.

82 *Transpower NZ Ltd, cross*-submission on HVDC Stage 1 MCP draft decision, p.2, available here.
83 *Transpower NZ Ltd, cross*-submission on HVDC Stage 1 MCP draft decision, p.3, available here.
84 *Transpower NZ Ltd, cross*-submission on HVDC Stage 1 MCP draft decision, p.3, available here.

Table 3.3 Major Capex Allowance for the HVDC Stage 1 MCP proposal ($m nominal)[85]

MCA component	MCA ($m nominal)
Supply and install four new submarine HVDC cables	871.0
Cable termination stations replacement	161.7
Benmore filter bank	23.8
Pole 2 overload scheme	15.6
New submarine cable storage facility	14.1
Project investigation costs	26.3
Stage 2 preparatory costs	26.1
MCA total	**1,138.6**

Major capex incentive rate

3.90 Our final decision is to set the major capex incentive rate for the HVDC Stage 1 MCP at 15%.

3.91 The major capex incentive rate we set 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.[86]

3.92 The Capex IM defines the major capex incentive rate at 15% – the default rate – or an alternative rate we specify after considering a request from Transpower. In its proposal, Transpower proposed that the default MCP incentive rate of 15% apply to the HVDC Stage 1 MCP.[87]

3.93 As we progressed our review of the HVDC Stage 1 MCP, we were satisfied that, while there are capital cost uncertainties, the Capex IM cost deadband introduced in the 2023 IM Review process and updated recently, will mitigate the extent of the reward Transpower will accrue, if it transpires that final project costs exceed estimates.[88]

Exempt major capex

3.94 Exempt major capex is the part of the MCA to which the major capex incentive rate does not apply. It is typically set for portions of the MCA that reflect uncertainties that are outside the control of Transpower.

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85 *Transpower New Zealand Ltd*, HVDC Stage 1 MCP Attachment 5 - Costing, Table 14, p.15, available here.

86 Capex IM, clause 3.3.5(7)(b).

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

88 *Commerce Commission*, Transpower investment topic paper, Part 4 Input Methodologies Review 2023 - Final decision, 13 December 2023, Section 3, p.41, available here.

3.95 In the proposal, Transpower has not proposed 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 not spending cost contingency amounts or penalised for spending them.

3.96 In this MCP the total project cost contingent amount, with reference to the P50 total project cost estimate, is $140.1 million ($ 2025) which is 14.3% of the total P50 project cost estimate of $978.1 million ($ 2025). In nominal terms the risk component is $171.2 million ($ nominal).[89]

3.97 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."[90]

3.98 This contingent amount, in percentage terms, is higher than previous major capex projects, and is mainly due to the cable installation risk component of $123.2 million ($ 2025).[91] This risk component is high due to route selection uncertainty, and weather-related installation issues that may impact cable laying costs in the Cook Strait.

3.99 We consider the project cost risks have a reasonable possibility of materialising and have included them in the MCA. This allows Transpower to recover those costs should the risks materialise.

3.100 However, 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.

3.101 Our approach is consistent with how we treat uncertainties relating to foreign exchange and inflation forecast error.

3.102 Our final 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.

3.103 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.[92] This incentive reward trigger is now set below the P30 MCA cost estimate of $1,049.6 million ($ nominal).

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89 Transpower response to RFI014 – Risk component in nominal terms.

90 *Transpower New Zealand Ltd*, HVDC Stage 1 MCP Attachment 5 - Costing, p.4, available here.

91 *Transpower New Zealand Ltd*, HVDC Stage 1 MCP Attachment 5 - Costing, Table 3, available here.

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

Incentive rate application

3.104 We recently amended the incentive rate formula for major capex applications.[93]

3.105 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.

3.106 The deadband was introduced in addition to the existing mechanism requiring us to set an amount of exempt major capex. Exempt major capex is that portion of the MCA to which the major capex incentive rate does not apply. For previous approved MCPs, we have typically set the exempt major capex in reference to the portions of the MCA that reflect uncertainties.

3.107 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.

3.108 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:

3.108.1 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;

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

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

Major capex project outputs

3.109 We evaluated Transpower's proposed major capex project outputs against the factors set out in clause C5(a) of Schedule C of the Capex IM: the extent to which the major capex project outputs reflect the nature, quantum, and functional capability of the transmission investment assets to be commissioned.[94]

3.110 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 much more likely in the future.

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93 Transpower Capital Expenditure Input Methodology (Major Capex Incentive Formula) Amendment Determination 2026 [2026] NZCC [XX]

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

3.111 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.

3.112 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 final decision is that the requirements of clause C5(a) have been met.

Approval expiry date and commissioning date assumptions

3.113 The commissioning date assumption is the date by which Transpower assumes the last asset of the HVDC Stage 1 MCP (if approved) will be commissioned.[95]

3.114 Transpower plans to deliver the HVDC Stage 1 MCP as several work packages with different forecast commissioning dates. Transpower has proposed a commissioning date for all assets by 31 December 2031.[96] We have evaluated Transpower's proposal and accept the proposed commissioning date assumption.

3.115 The approval expiry date is the date beyond which Transpower cannot recover the costs of any major capex project assets, and any MCP outputs it has not yet commissioned by that date.[97]

3.116 We have evaluated the approval expiry date proposed by Transpower.[98] Following our review of the proposed investments, we consider Transpower can deliver the projects in the proposal by the approval expiry date.

3.117 Our final decision is to accept that the proposed approval expiry date of 31 December 2036, is reasonable.

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95 Capex IM, clause 3.3.5(6)(e) and C1(3)(h). Definition of 'commissioning date assumption' under clause 1.1.5(2) of the Capex IM.

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

97 Capex IM, clause 3.3.5(6), C1(3) and C4. Under clause 3.3.6(1)(d) of the Capex IM, Transpower may apply to us to amend the approved approval expiry date.

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