TRANSPOWER

HVDC Link Upgrade Programme Major Capex Proposal (Stage 1)

Overview

September 2025

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1 Overview

This is a Major Capex Proposal (**MCP**) to the Commerce Commission under the Transpower Capital Expenditure Input Methodology Determination (**Capex IM**).[1]

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.

Transpower owns and maintains the HVDC link on behalf of the people of New Zealand. We continually monitor the condition of the HVDC link and invest in maintenance and upgrades to ensure it performs to a standard that meets the nation's electricity needs of today and into the future.

Key to the HVDC link are the submarine cables that run across the Cook Strait seabed. These three cables were installed in 1991, are approaching the end of their 40-year design life and are expected to require replacement by 2032. As cables age, the risk of failure increases significantly. Our condition assessment confirms that the cables are aging as expected and should be replaced by 2031 to maintain the reliability of the HVDC link. Should the cables fail, the outage impact could be significant for communities and businesses across New Zealand. Reactive repair of any failure – if even possible – would be technically complex, expensive and is likely to take a long time.

As such, a plan to address the end-of-life HVDC cables needed to be developed. The plan needed to be deliverable by 2031 and provide the greatest expected net electricity market benefit to the people of New Zealand, given the significant investment required.

This MCP sets out that plan.

To identify the best solution for New Zealand, one that balances affordability against the critical importance of these assets, there are two main challenges we need to overcome.

- As the three existing submarine cables age, the risk of failure increases significantly, and delays in replacement could lead to prolonged outages and significant disruptions to New Zealand's electricity sector,
- Lead times for procurement and installation range between seven and ten years due to strong international demand, as nations electrify their economies, and the limited availability of the specialised vessels required.

In light of these challenges, Transpower has been consulting on aspects of the HVDC link since 2022. At every step, stakeholder feedback has confirmed the critical role of the HVDC link and the need for proactive intervention to avoid potential failure. When considering all

1 Transpower Capital Expenditure Input Methodology (IM Review 2023) Amendment Determination 2023.

the options available, stakeholders have consistently and overwhelmingly supported the option to replace the HVDC cables.

Given the work that is required, and that this work will not be expected to be repeated for another 40 years, we have also considered, and consulted on, whether stakeholders see value in enhancing the HVDC link's north transfer capacity from 1200 MW to 1400 MW – which is the maximum transfer capacity we can achieve without replacing all of the HVDC equipment.

Consultation to date has shown stakeholders broadly agree with the option of increasing capacity on the HVDC link, recognising that delivering a capacity upgrade separately to the cable replacement would incur significantly higher costs.

As we consider both replacing and upgrading the HVDC cables, we have also reviewed other critical HVDC components to ensure the HVDC link operates reliably and effectively.

The HVDC control systems are nearing the end of their expected operational life and are due for replacement around 2033, while upgrades are also required to improve the seismic performance of the cable termination stations at both ends to meet modern engineering standards.

Therefore, with a view to minimising costs, planned outages, and disruption to the electricity market, we've identified that it would be optimal to replace the HVDC control systems and the cable termination stations at the same time as we replace the cables. We have also considered the removal and disposal of the three existing submarine cables after they are decommissioned.

Given our need to maintain an affordable electricity system, and be prudent with our spending, such an investment requires very robust consideration. For that reason, we have obtained an independent expert review of our proposed investment.

Earlier in 2025, we consulted on three investment options, outlining what we considered to be the preferred option. After considering stakeholder submissions, our preferred option remains to replace the three existing submarine cables with four new cables to support 1400 MW north transfer, along with upgrades to the cable termination stations, control systems and other necessary works. This is the first stage of the proposed investment set out in this MCP, for the Commerce Commission's consideration.

Since our short-list consultation, we now plan to seek approval for this work in stages. This MCP is focused on investment in the cable replacement, cable termination stations, and associated works (**Stage 1**).[2] We will submit a subsequent stage MCP for the HVDC control systems replacement and recovery of the decommissioned submarine cables,[3] allowing further engagement with the market to refine scope and cost estimates – see *Anticipated future stages* discussion below.

This MCP seeks Commerce Commission approval to recover the costs of the proposed Stage 1 investment as summarised in Table 1. We propose a major capex allowance (MCA) for Stage 1 of $1,138.6 million, with a detailed breakdown provided in Table 2.

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2 The proposed Stage 1 investment is an alternative to the HVDC cables replacement listed project in Schedule 1 of the Transpower Individual Price-Quality Path Determination 2025.

3 This includes the removal of the existing submarine cables and the new cables.

Table 1: HVDC Link Upgrade Programme MCP (Stage 1) at a glance

HVDC Link Upgrade Programme MCP (Stage 1) at a glance	
What:	Ensure a reliable and resilient electricity supply that meets growing demand by addressing risks linked to the aging condition of the HVDC submarine cables and associated infrastructure. We will achieve this through the following outputs: • procure, install, and commission four new HVDC submarine cables, increasing the HVDC link's transfer capacity north from 1200 MW to around 1400 MW; • construct and commission new cable termination stations and associated equipment located at Oteranga Bay (North Island) and Ōraumoa Fighting Bay (South Island), along with necessary modifications to the existing overhead line connections; • procure, construct, and commission an additional filter bank at Benmore substation to facilitate continuous operation at the increased capacity of around 1400 MW; • works to increase the Pole 2 overload capacity at Haywards and Benmore; • construct and commission a new submarine cable storage facility and associated infrastructure and equipment to house spare cable lengths for future maintenance and repairs; and • preparatory work for a potential Stage 2, including early engagement with vendors and suppliers to refine scope and confirm cost estimates for anticipated future stage projects.[4] Each of the four new submarine cables will be approximately 40km in length and installed within designated cable routes in the Cook Strait Cable Protection Zone (CPZ). They will connect to the upgraded termination stations.
When:	Commence work as soon as funding is approved Commissioning date assumption (commissioning date of last Stage 1 investment): 31 December 2031
How much:	Major Capex Allowance: $1,138.6 million.
Incentive elements:	Major capex incentive rate: Default rate of 15%
Approval expiry date:	31 December 2036[5]

4 Capex for the preparatory work will be held as works-under-construction until there is a Stage 2 asset in which to capitalise it.

5 We propose an approval expiry date of 31 December 2036, being five years after the commissioning date assumption. We have proposed this extra period because this allows for any unforeseen delay in mobilisation, construction or commissioning that may be caused by unexpected events. If this happens it will be efficient to have a reasonable window during which we will not have to re-apply for investment approval.

Table 2: Proposed Stage 1 Investment MCA breakdown

Investment	Expected capital cost (P50, real 2025 $m)	MCA (nominal, incl. inflation, escalation and interest during construction)	Expected commissioning / delivery date
Supply and installation of four new submarine cables to support 1400 MW north transfer	760.4	871.0	2031
Cable termination stations replacement	134.5	161.7	2031
Benmore filter bank to enable 1400 MW	19.7	23.8	2031
Pole 2 overload scheme	12.7	15.6	2031
Establishment of new submarine cable storage facility	11.6	14.1	2031
Project investigation costs	19.5	26.3	2031
Stage 2 preparatory costs	19.6	26.1	
Total	**978.1**	**1,138.6**	

Anticipated future stages

While we have included the HVDC control systems replacement and recovery and disposal of the submarine cables (decommissioned existing and new) in our overall plan and Capex IM investment test (**Investment Test**) analysis, we do not have sufficiently detailed cost estimates to be confident enough to include these works in Stage 1.

We have, however, proposed preparatory funding to undertake further and more detailed investigations in preparation for a subsequent stage MCP.

Our investigations will include further engagement with international suppliers to further develop and define the scope and cost of the control systems replacement, which is highly specialised. Similarly, we plan to undertake further analysis of the cable recovery work to better define the associated scope and costs.

Once we have this information, we plan to submit a subsequent MCP to the Commerce Commission covering these works.

We expect our subsequent MCP to include the investments outlined in Table 3, consistent with the analysis underpinning this MCP.

Table 3: Anticipated investments for HVDC Link Upgrade Programme future stages

Anticipated investments for HVDC Link Upgrade Programme future stages	
What is likely to be included:	Outputs
• *HVDC control system replacement* • *Recovery and disposal of the three decommissioned existing submarine HVDC cables* • *Provision for the future recovery and disposal of the new submarine cables*	• *New HVDC control systems equipment and facilities at Haywards and Benmore* • *Recovering and disposing of the three 1990s existing submarine cables after decommissioning* • *Provision for the future recovery and disposal of the new submarine cables when they reach end of life*

A barge laying a small section of submarine cable in Oteranga Bay in 2005 to complete a repair.

This MCP includes this overview document and ten attachments as listed here:

- Attachment 1 – Compliance with the Capex IM
- Attachment 2 – Need for investment, demand and generation scenarios
- Attachment 3 – Cable Condition Report
- Attachment 4 – Short-list of investment options
- Attachment 5 – Costing Report
- Attachment 6 – Benefits modelling
- Attachment 7 – Application of the Investment Test
- Attachment 8 – Stakeholder engagement
- Attachment 9 – Transmission Pricing Methodology and Indicative Pricing Impacts
- Attachment 10 – CEO certification

2 Enabling growth and resilience: The vital role of the HVDC link

The HVDC link is a vital piece of infrastructure that connects the North and South Islands' electricity transmission systems and enables the reliable and efficient delivery of electricity to communities and businesses around New Zealand.

Spanning 570 kilometres from Benmore substation in the South Island to Haywards substation in the North Island, the HVDC link includes both overhead lines and three submarine cables that traverse Cook Strait (see Figure 1). At peak, the HVDC link can currently move up to 15% of New Zealand's total electricity load.

Operating at 350 kV, the HVDC link consists of two separate circuits with two converter systems at each end, converting voltage between the HVDC link and the 220 kV (AC) transmission lines that connect into them. These converters are called Pole 2 and Pole 3.[6]

The HVDC link plays a vital role in ensuring a reliable and efficient electricity system.[7] Most of the time, the HVDC link is moving lower-cost, hydro generation from the South Island to users in the North Island. This enables South Island hydro generation to play a role in 'firming' the electricity system, something that will be needed more often with the increasing volume of intermittent wind and solar generation being installed in the North Island.

Firming generation is required when intermittent generation is not available, such as if the wind is not blowing or the sun is not shining. Hydro generation is ideally suited for this purpose; however, the North Island lacks sufficient hydro capacity and there are currently no plans to materially increase it. Therefore, South Island hydro generation, transmitted over the HVDC link, plays this role.

North Island generation can and does also flow to the South, which happens mostly during dry years when hydro storage is low, such as was seen during winter 2024 and early 2025.

The HVDC link also enhances competition by integrating the North and South Island electricity systems into a single wholesale market, encouraging efficient dispatch and generation investment. Technological upgrades of the HVDC link, including the 2013 Pole 3 project, have improved key aspects of system functionality such as reserve sharing and frequency management.[8] These advancements support greater resilience within the system and reduce the risk of outages; they also reduce costs for consumers by allowing seamless electricity transfer and shared grid frequency control between islands.

As New Zealand and its economy grows, demand for electricity increases, and more renewable generation connects to the national grid, it will become even more critical to maintain the HVDC link's reliability and capacity.

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6 Pole 1 was retired following the commissioning of Pole 3 in 2013.

7 Transpower is subject to several revenue-linked service performance measures, this includes a requirement that the HVDC link is 98% available.

8 Keeping the lights on with reserves | Electricity Authority

Work that is already underway following the Commerce Commission's approval of Transpower's Net Zero Grid Pathways Phase 1 (NZGP 1.1) project will enhance the HVDC link's performance, allowing it to operate closer to its full capacity more often. These investments will increase the average maximum electricity transfer between the North and South Islands, raising the northward transfer capacity from a historical average of 1070 MW to almost 1200 MW.[9] The outcomes of this work have supported the development of this MCP and are enablers to what is being proposed here.

However, as with all infrastructure, the HVDC link and its associated operating systems have an end-of-life point when they can no longer be effectively maintained without exposing the system to an increasing risk of failure. As such, proactive intervention is essential to preserve the HVDC link's performance. Proactive intervention also provides a once-in-a-generation opportunity to enhance the HVDC link to ensure it can continue to function as a key enabler of New Zealand as our nation grows and changes to deliver a lower-carbon, more electrified future.

Figure 1: Overview of the New Zealand transmission network showing the HVDC link

9 The design capacity of the HVDC converter stations at Haywards and Benmore substations is 1400 MW northward.

2.1 The HVDC link includes three submarine cables

The three existing submarine cables were installed in 1991 and have a design life of 40 years: their expected end-of-life replacement need date is 2032.[10] Each cable is approximately 40 kilometres in length, running between Ōraumoa Fighting Bay on the coast of the South Island and Oteranga Bay on the coast of the North Island.

Given their exposure to the harsh environment of Cook Strait, where strong tidal currents continuously move gravel across the cables, and the fact that some cable sections are suspended across undersea outcrops, they are particularly vulnerable to ongoing physical degradation, and damage from severe storms and dragging anchors.[11]

To safeguard these cables from third party damage, a designated cable protection zone was established along the cable routes, prohibiting anchoring and fishing activities. This zone is patrolled year-round, 24/7, by a dedicated cable patrol ship, to mitigate these risks.

Annual condition assessments, including electrical tests, remote-operated vehicle surveys, and diver inspections provide critical insights into the state of the cables. These assessments help Transpower identify and mitigate damage, ensuring the cables remain operational for as long as possible.

Regardless of monitoring and repair, this approach cannot prevent the inevitable degradation of this infrastructure as it ages and approaches its end-of-life; assessments consistently show progressive wear, increasing vulnerability, and a rising likelihood of failure. Transpower's asset health model, which uses industry data and historical performance trends to predict future performance, confirms that the rate of deterioration is accelerating. These assets will soon reach their retirement age.

Given this information, we believe that the cables need to be replaced, if we are to maintain the reliability of the HVDC link and secure the future transmission of electricity between the North and South Islands as our nation and economy, grows.

2.2 Recent engagement on the HVDC link

We have undertaken recent engagement with customers and other stakeholders so they could give us their thoughts and feedback on: the current condition of the submarine cables; the future role of the HVDC link in New Zealand's electricity system and economic growth; and whether there is a need for upgrades to the HVDC link's capacity.

Formal consultations have included:

- **Net Zero Grid Pathways 1.1 (NZGP 1.1) MCP (December 2022)[12]:** This proposal covered investments to install HVDC reactive plant, filter banks and associated equipment to upgrade the HVDC link's northward transfer capacity from 1071 MW to closer to

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10 End-of-life means end of design life. It does not mean that the cables will stop functioning in 2031, but that the risk of failure beyond that time increases.

11 In 2016, storm Angus in the English Channel caused a ship's anchor to drag and damage four out of eight cables on the Cross-Channel HVDC Link.

12 [Net Zero Grid Pathways | Transpower]

1200 MW. Further potential capacity enhancements beyond 1200 MW were identified for consideration in a future stage (refer to section 2.3.2). The MCP was approved by the Commerce Commission and work is underway with an intended commissioning before 2029. This programme provides a strong foundation for the investments proposed in this MCP.

- **Examining the purpose and future role of our HVDC link (March 2024):** [13] This discussion paper sought input on the long-term role of the HVDC link. It outlined the challenges and opportunities associated with maintaining a fit-for-purpose HVDC link in line with increased electrification and forecast growth in renewable energy generation. Stakeholders unanimously agreed on the importance of the HVDC link and expressed strong interest in further modelling to understand the benefits and trade-offs of future investment decisions.
- **HVDC cable replacement and enhancement consultation (August 2024)** [14]**:** This consultation discussed the need to begin planning for the replacement of the submarine cables. Stakeholders broadly supported replacing the cables by the early 2030s to minimise the risk of failure. There was also broad agreement on the option of taking this opportunity to examine increasing the capacity to 1400 MW north transfer during the replacement process, recognising the significant costs and long lead times associated with addressing an upgrade at a later date. Earlier work has shown that 1400 MW north transfer is the maximum achievable without major further investment. Any increase beyond this would require substantial upgrades to the wider HVDC link, which Transpower does not consider cost effective or economic at this time.
- **HVDC Upgrade Programme short-list consultation (May 2025):** refer to section 3.2 of this document.

Stakeholders have consistently agreed that the HVDC link is critical in maintaining an interconnected national grid and single wholesale electricity market; ensuring the reliable and efficient dispatch of generation between the North and South Islands; supporting system performance in reserve sharing, frequency management and firming, and in supporting New Zealand's future growth and energy transition.

2.3 The need for investment

2.3.1 Ageing submarine cables: Mitigating the risk of failure and outages

By 2031 the cables will be 40 years old and will have reached the end of their expected life. Transpower's inspections and asset health data confirm that replacement will be necessary by 2032 to minimise increased risk of failure.

Continuing to operate the cables beyond 2032 raises the risk of failure, and therefore risks outages and placing the security of New Zealand's supply at risk. While a short-term, unplanned HVDC outage may not have immediate security of supply implications, a failure during dry hydrological conditions in the South Island or during North Island capacity shortages, is likely to create security of supply challenges.

13 Discussion paper - Examining the purpose and future role of our HVDC link - March 2024
14 HVDC Cable Replacement and Enhancement Information and Consultation paper – August 2024

Regardless, maintaining or seeking to repair the cables beyond 2032 is not considered a viable option. Repair durations typically range from 6 to 18 months, and with electrification investment accelerating, these timeframes are likely to extend in the future.

If failure occurred and the damage was irreparable, restoring the HVDC link to full capacity would be impossible until a replacement cable was installed.[15]

During our NZGP 1.1 investigations we engaged with vendors to better understand the international submarine cable market. Global demand for submarine HVDC cables has surged, driven by the expansion of interconnectors, offshore wind generation and the corresponding need for undersea transmission infrastructure. Submarine HVDC cable installation is now offered as a bundled service with cable manufacturing, and this work requires specialist vessels with significant cable-carrying capacity, which are few in number and in high demand worldwide.

Feedback indicated the procurement, manufacture and installation of a replacement HVDC submarine cable is approximately 7-10 years. This extended timeline is partly due to New Zealand's isolated location, as well as the high demand for submarine cables from large northern hemisphere projects.

If New Zealand were to find itself facing the irreparable damage of a cable, it would disrupt the electricity market and result in significant negative economic impact to New Zealand through increased costs and disruption.

As a result, and in anticipation of this work, we took proactive steps to secure suppliers in 2024, to ensure we could meet New Zealand's needs. At the end of 2024 we entered into a capacity and reservation agreement with global cable solutions supplier Prysmian for

Annual health assessments of each cable include underwater surveys to identify and address any damage.

15 'HVDC Submarine Cable Replacement and Enhancement Investigation (NZGP) – HVDC Submarine Cables Q&A', Transpower, 6 April 2023. HVDC Stage 1 Enhancement Project Analysis | Transpower

submarine cable manufacture and installation, which provides us with a procurement pathway for the submarine cables.

2.3.2 Future-proofing the HVDC link: Enhancing capacity

Increasing the HVDC submarine cable capacity from 1200 MW to 1400 MW north transfer would align the cables with the existing capacity of the HVDC overhead lines and the Pole 2 and Pole 3 converter transformers at Haywards and Benmore substations. This would then ensure existing capacity in these other assets could be utilised. Previous modelling undertaken as part of the NZGP 1.1 investigations identified a positive net electricity market benefit from a capacity increase from 1200 MW to 1400 MW north transfer, although this enhancement was not included in the NZGP 1.1 MCP to the Commerce Commission.

The benefits of increasing HVDC capacity arise primarily from the growing volume of forecast intermittent renewable generation, such as wind and solar, being developed in the North Island. Consequently, it is expected that a significantly greater proportion of future transfers across the HVDC link will be South Island hydro-electricity, needed to firm intermittent generation in the North Island.

Increasing the HVDC link's north transfer capacity to 1400 MW could also offer additional benefits to the electricity market in terms of reliability. A four-cable configuration supporting 1400 MW north transfer provides greater redundancy across the system, reducing the potential impact should a single cable fail.[16]

Additionally, NZGP 1.1 modelling found that the HVDC link will increasingly set the electricity market reserve risk, as the amount of instantaneous reserve needed is determined by the largest part of the system that could fail. This is usually either the largest generation unit that is running or the transfer across one HVDC Pole. As HVDC utilisation increases, it will more frequently set the system risk and reserve requirements. Increasing the HVDC link's north transfer capacity to 1400 MW provides the option to increase the overload capacity for Pole 2, allowing it to absorb additional load for up to 15 minutes in the event of a Pole 3 trip. This enhancement would improve overall network stability and reduce costs by allowing the HVDC link to cover a larger portion of its own reserve requirement.

Increasing the capacity of the HVDC link at the same time as replacing the existing cables is likely our only practical opportunity to do so. Combining these efforts provides significant delivery efficiencies, as utilising a single cable-laying ship and coordinating the work reduces cost. A substantial portion of the cable costs is driven by manufacturing setup and ship mobilisation to New Zealand, making an upgrade in conjunction with replacement the most cost-effective approach.

2.3.3 Replacement of connected HVDC infrastructure: Control systems and cable termination stations

The HVDC control systems, installed in 2013 alongside Pole 3, manage the operations of both Pole 2 and Pole 3 and associated AC reactive power controls. These bespoke systems were specifically designed for New Zealand's two-island power grid.

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16 Increasing the capacity of the HVDC link to 1400 MW north transfer will require the installation of an additional filter bank at Benmore to manage damaging harmonic currents at higher transfer levels and fully realise the increased capacity.

Unlike core converter infrastructure, HVDC control systems have a shorter lifespan, driven by rapid technological change: typically 15 to 20 years. By 2033 the current systems will be 20 years old and at the end of their expected life. What's more, the hardware platform they operate on is already being phased out, with spare parts no longer produced and limited ongoing support available. Once manufacturer support ends, Transpower may be unable to address critical failures, increasing the risk of prolonged, and potentially system critical, outages.

The complexity of the work, high global demand for product, scale of preparation, testing requirements and lead time required means the process of market engagement, procurement and design, must begin now to ensure timely delivery and minimise system disruption. Because the system controls both poles, its replacement must be closely coordinated with the planned cable replacement. Aligning these works will minimise construction and commissioning outages, reduce market impacts, and avoid the risk of the new cable benefits being compromised by an aging control system.

Work is also required to improve the seismic performance of the land-side cable termination stations at each end of the submarine cables. These stations need structural strengthening to meet modern engineering standards for seismic performance of critical infrastructure.

Because of the extensive engineering strengthening work required, working within these buildings containing live equipment is not safe or practicable and extended outages of the HVDC link would be required. A more cost-effective and safer approach is to construct new termination station buildings. This would eliminate the need to work within an active building, reducing extended HVDC outages, and improving safety. It also provides the opportunity to consider long-term resilience against climate related risks within the building designs.

Furthermore, a dedicated cable storage facility must be established to accommodate spare cable lengths that will be included in any HVDC cable replacement order. This requires developing an appropriate storage turntable and infrastructure to ensure long-term integrity of the spare cable.

3 Options to address the need

3.1 Our long-list of investment options

We considered a long-list of investment options to address the identified need.

These were grouped into three categories:

1. **Non-transmission solutions (NTS)**
   a) Alternatives aimed at decreasing or eliminating the need for a transmission investment.
2. **Transmission solutions: existing assets**
   a) Do nothing: allow the cables and associated equipment to run to failure and then decommission the HVDC link.
   b) Like-for-like cable replacement: Replace the cables and associated equipment with a capacity of 1200 MW, maintaining current capacity.
   c) Cable capacity increase: Replace the cables and associated equipment with the addition of a fourth cable to support increased capacity (e.g., 1400 MW north transfer).[17]
   d) Cable capacity decrease: replace the cables and associated equipment with a lower capacity solution.
3. **Transmission solutions: new assets**
   a) Constructing a completely new HVDC inter-island link.
   b) Constructing a completely new AC inter-island link.

Each long-listed option was assessed on its ability to address the identified need using our short-listing criteria. Further detail on the process is provided in Attachment 4. The evaluation determined that:

- Replacing the cables with either the same capacity (like-for-like) (2.b) or increasing capacity (2.c) are the only credible options,
- Considering the condition-based need to replace the HVDC cables and the scale of the load, we believe that NTS (1.a) are unlikely to provide a viable alternative to transmission for the HVDC link as a backbone grid asset. This view was supported by stakeholders, with no objections raised during our short-list consultation,
- The “do nothing” option (2.a) is a run-to-failure strategy rather than a viable maintenance pathway. The existing undersea cables have reached retirement age and

17 Additionally, our NZGP1.1 long-list consultation document identified a range of potential transmission enhancements to address broader grid challenges for achieving a net-zero future. These included HVDC capacity enhancements, 220 kV capacity upgrades in the Central North Island (Bunnythorpe-Whakamaru), and improvements to the Wairakei Ring. Among the options a 1200 MW HVDC was considered along with increasing the HVDC link’s north transfer capacity from 1200 MW to 1400 MW to utilise the higher available capacity of the existing HVDC converters. The NZGP 1.1 consultation documents, submissions and final MCP proposal can be found here.

increased risk of failure. They cannot be proactively maintained or repaired once deterioration sets in. A failure would cause extended outages and major disruption, given the long lead times for replacement. The HVDC control systems are also obsolete, with critical components no longer supported or available. Continued reliance on these assets carries a high risk of unplanned failure. Without targeted investment, the HVDC link cannot continue to operate reliably,

- Replacing the cables with lower capacity alternatives (2.d) was not short-listed as it would undermine the HVDC link's role in supporting New Zealand's future energy demands and projected growth. Any cost savings from lower capacity alternatives would be negligible given the high mobilisation and installation costs of laying submarine cables in the South Pacific,
- Constructing either a new HVDC link (3.a) or HVAC link (3.b) is cost-prohibitive compared to utilising the existing HVDC infrastructure.

We decided that, given the limited number of viable alternatives for cable replacement, and the strategic options already discussed with stakeholders in NZGP 1.1 regarding HVDC capacity upgrades, a long-list consultation held little value. The Commerce Commission approved our proposal not to carry out a separate long-list consultation to support this MCP.

The Commerce Commission also supported our view that NTS is unlikely to provide a viable alternative to a transmission investment, subject to any contrary feedback from our short-list consultation.

3.2 Our short-list of investment options

The short-list of investment options for this project are:

- **Base Case (Option 1) – No investment:** The HVDC cables, control systems and termination stations are not upgraded. Over time, as critical components fail, the HVDC link is decommissioned. This is not considered a viable option but has been included as a base case to allow us to quantify the benefits of investment,
- **Option 2 – Like-for-like replacement:** Replacement of the three HVDC submarine cables with three new cables with a combined 1200 MW capacity, along with required upgrades to the termination stations and control systems and associated works,
- **Option 3 – Increased capacity:** Replacement of the HVDC submarine cables, including the addition of a fourth cable to support 1400 MW capacity north, alongside required upgrades to the termination stations and control systems and associated works.

The short-list of options was first shared with stakeholders via a press release on 7 May 2025 and we consulted on the short-list options between 7 May and 20 June 2025.[18]

The consultation paper included our preliminary application of the Investment Test which identified Option 3 – Increased capacity as the option providing the highest positive expected net electricity market benefit and, therefore, the preferred option.

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18 Consultation details, including the consultation paper and a summary of submissions, are published at HVDC link upgrade programme | Transpower.

During our short-list consultation most stakeholders supported the need for investment to ensure a reliable HVDC link into the future, and that increasing the capacity and including the other associated works at the same time made sense.

Stakeholders expressed no concerns with our treatment of NTS in the short-list consultation, and no alternative solutions were proposed.

Some stakeholders queried the necessity of removing the decommissioned submarine cables, given the high associated cost of removal, and suggested that this aspect of the project warrants further scrutiny. Following that feedback we have decided to explore that aspect further as a subsequent stage.

Further details on our short-listed options and our stakeholder engagement can be found in Attachment 4 and Attachment 8 of this MCP.

4 Investment Test inputs and assumptions

To identify a proposed investment, we conducted a cost-benefit analysis of our short-list using the Investment Test. For a proposed investment to satisfy the Investment Test, it must be the investment option which maximises expected net electricity market benefit relative to the other investment options considered. For this proposed investment, the expected net electricity market benefit must also be positive.

The costs considered in the Investment Test include capital expenditure as well as ongoing operation and maintenance costs. Benefits are calculated using models of the New Zealand electricity system to estimate the relative benefits of alternative investment options.[19] Costs and benefits are discussed in greater detail in Attachments 5, 6 and 7.

Applying the Investment Test requires several key assumptions, including assumptions about electricity demand growth and future generation capacity (demand and generation scenarios). We have used four scenarios and have weighted them equally in this analysis.

Attachment 2 provides more detail on the demand and generation scenarios that we used in this analysis. These scenarios build upon the ones we consulted on and included in our NZGP 1.1 MCP in December 2022 and on the additional analysis we conducted to inform our August 2024 paper, HVDC cable replacement and enhancement consultation. We have incorporated market announcements and any relevant information received since this time.

We also use assumptions in calculating the present value of future cash flows. Attachment 7 provides more detail of the assumptions used in our application of the Investment Test.

19 The types of costs and benefits we consider in the Investment Test are specified in the Capex IM.

5 Application of the Investment Test

Our application of the Investment Test has considered the costs and benefits of each short-listed option.

Table 4 presents the total discounted capital costs and benefits for each option out to 2060. To fairly compare options, we present total costs and benefits as present values, incorporating the phasing of investment and the benefits expected over time. The costs incurred for the cable replacement options reflect an expected commissioning date of 2031.

We considered the electricity market benefits for the three options. The benefits considered are:

- **System cost savings** – maintaining or enhancing the HVDC link enables efficient power transfer between the North and South Islands, reducing the need for local generation investments and lowering long-term capital costs. It also optimises generation dispatch, prioritising lower-cost renewable energy over more expensive thermal generation, thereby reducing fuel costs, emissions and operational expenses,
- **Deficit avoidance** – without investment, electricity supply will not meet forecast demand, forcing consumers to curtail usage or seek alternative power sources,
- **Reserve costs savings** – HVDC capacity affects the need for instantaneous reserves to mitigate unplanned outages, such as generator failures or HVDC pole faults. These reserves can be supplied by generation, batteries, or interruptible demand.

To satisfy the Investment Test, a proposed investment must maximise expected net electricity market benefit relative to the other investment options considered. For this proposed investment, the expected net electricity market benefit must also be positive.

The expected net electricity market benefit is calculated as the difference between total benefits and total costs (shown in Table 4).[20] The final column provides a comparison with Option 2 – Like-for-like replacement, as a reference.

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[20] The total costs in Table 4 are the sum of the project cost of the relevant investment option (capital cost and associated operating and maintenance costs) and the capital costs of modelled projects for the investment option. The Investment Test contemplates that the capital costs of modelled projects will be treated as an electricity market cost element (a negative benefit). Treating the capital costs of modelled projects as part of the total cost of the relevant investment option instead does not affect the outcome of the Investment Test.

Table 4: Summary of discounted costs and benefits for investment options

Option	Description	*Total costs (PV 2025 $m) *A*	Total benefits (PV 2025 $m) *B*	Expected net electricity market benefit (PV 2025 $m) *B-A*	Relative Expected net electricity market benefit (PV 2025 $m)
1	No investment	475.2	0.0	-475.2	-3226.9
2	Like-for-like replacement, 1200 MW	1995.4	4747.2	2751.7	0.0
3	Increased capacity, 1400 MW	2107.2	4925.2	2818.0	66.3

* The total costs for an investment option is the sum of capital cost for the option, O&M costs for the option, and (significantly for Options 2 and 3) capital costs for modelled projects associated with the option. The capital cost of the Base Case (Option 1) – No investment primarily consists of expenses for recovering the existing cables and decommissioning the HVDC link.

The results show that Option 3 - Increased capacity has the highest, and positive, expected net electricity market benefit. Based on this analysis, Option 3 - Increased capacity is our proposed investment.

A sensitivity analysis on our net-benefit calculations can be found in Attachment 7. The sensitivity analysis reinforces the robustness of Option 3 – Increased capacity, showing that it maintains the highest expected net electricity market benefit across a wide range of input variations.

6 Proposed investment

Based on our application of the Investment Test, we have concluded that Option 3 – Increased capacity, is our proposed investment. This conclusion was supported by strong and widespread stakeholder endorsement during our consultation process.

Option 3 – Increased capacity has the highest positive expected net electricity market benefit across a range of scenarios and sensitivity cases. It shows that there is additional benefit to increasing the capacity of the HVDC link to 1400 MW north transfer compared with Option 2 - Like-for-like replacement. These additional benefits arise because much of the forecast new generation to be built will be intermittent renewable generation in the North Island. As discussed in section 2.3.2, and as a consequence of this new generation, a significant proportion of the transfers across the HVDC link will be the northward transfer of South Island hydro-electricity, used to firm North Island intermittent generation.

Also, as discussed in section 2.3.2, our modelling indicates that the HVDC link will increasingly set the reserve risk in the future.

These factors strongly support the case for Option 3 – Increased capacity as a prudent investment on New Zealand's national electricity transmission grid.

6.1 Staging

While all components of the programme are included within the Investment Test, we propose a staged approach to manage cost estimation risks. This reflects current uncertainty in the scope and the estimated cost of two key components: the replacement of the HVDC control systems, and the removal of the decommissioned submarine cables.[21]

While the HVDC control systems replacement and the recovery of decommissioned submarine cables are part of our proposed investment and have been included in the Investment Test analysis, these components are not yet sufficiently developed to be included in Stage 1. These elements are common to both Option 2 – Like-for-like replacement and Option 3 – Increased capacity. This means that changes in their cost does not affect the outcome of the Investment Test between these two investment options.

Despite efforts to refine these cost estimates, we consider it prudent to defer seeking approval for these components. Instead, we propose to seek approval for them in a subsequent stage, once further design, costing, and planning work has been completed.

Accordingly, we are proposing a staged investment approach with most works being included in Stage 1, while allowing us to progress the necessary planning and market engagement to inform a subsequent stage MCP to the Commerce Commission. This approach provides transparency to consumers, reduces estimation risk, and ensures we seek approval for Stage 2 investments only once they are sufficiently scoped. While cost refinements at Stage 2 are expected, they are not anticipated to materially affect the strong economics of maintaining an HVDC link beyond the 2030s or alter our proposed investment, given the significant positive net benefit. We remain committed to presenting the most accurate cost estimates in our Stage 2 proposal.

7 Application to the Commerce Commission

Stage 1 is a Staging Project of a Major Capex Project (Staged) under the Capex IM. The Major Capex Project (Staged) status means that we need to submit a MCP to the Commerce Commission, seeking approval to recover the costs of Stage 1.

The table below outlines Transpower's proposed Stage 1 investment for the HVDC Link Upgrade Programme. Costs associated with the HVDC control systems replacement and recovery of decommissioned submarine cables are not included in Stage 1; we intend to seek approval for those works as a subsequent stage, once the scope and costs are confirmed. We

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21 This includes the removal of the existing submarine cables and the new cables.

have included an allowance to work with international control system vendors to confirm these Stage 2 requirements.

Table 5: Proposed Stage 1 Investment MCA breakdown

Investment	Expected cost (P50, real 2025 $m)	MCA (nominal, incl. inflation, escalation and interest during construction)	Expected commissioning / delivery date
Supply and installation of four new submarine cables to support 1400 MW north transfer	760.4	871.0	2031
Cable termination stations replacements	134.5	161.7	2031
Benmore filter bank to enable 1400 MW	19.7	23.8	2031
Pole 2 overload scheme	12.7	15.6	2031
Establishment of new submarine cable storage facility	11.6	14.1	2031
Project investigation costs	19.5	26.3	2031
Stage 2 preparatory costs	19.6	26.1	
Total	**978.1**	**1,138.6**	

7.1 Major Capex Allowance and Indicative Pricing Impact

Transpower is seeking a Major Capex Allowance (MCA) to recover the costs associated with this investment. The Commerce Commission determines how much revenue Transpower can recover from its customers. The Transmission Pricing Methodology[22] (TPM) determines how revenue is recovered from each of Transpower's customers in each pricing year.

If approved, cost recovery will occur through transmission charges (specifically, benefit-based charges) under the TPM once the relevant assets are commissioned.

22 Schedule 12.4 of Code - Part 12 - Transport 17 June 2024.pdf.

The proposed MCA for the proposed Stage 1 investment is provided in Table 6 below. The MCA is larger than Transpower's expected capital cost because it includes inflation and interest during construction.

Once commissioned, the proposed Stage 1 investment will be classified as a benefit-based investment under the TPM. The costs of the benefit-based investment will be recovered through benefit-based charges under the TPM, from customers who are expected to benefit from the investment. The benefit-based charges will be allocated to customers in proportion to their expected positive net private benefits.

Table 6: MCA for Proposed Stage 1 Investment

Expected capital cost (P50, real 2025 $m)	Major Capex Allowance (nominal $m)
978.1	1,138.6

If the Commerce Commission approves cost recovery for the proposed Stage 1 investment, then the proposed starting benefit-based investment customer allocations will be calculated using the price-quantity standard method[23] under the TPM.

Indicative starting allocations and indicative benefit-based charges are presented in Attachment 9.

8 Next steps

This MCP marks a significant milestone in our process for investing in New Zealand's electricity transmission network. The next step is for the Commerce Commission to review and consider this MCP and determine whether to approve cost recovery for the proposed Stage 1 investment.

23 There are two standard methods – the price-quality method, and the resiliency method. This isn't a resiliency investment so the price-quality method applies·
Information sheet on benefit-based charges: Standard method

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