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# Decision and reasons on Stage 1 of Transpower's Waikato and Upper North Island Voltage Management staged major capex project

## [2020] NZCC 20

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**Date:** 23 September 2020

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# Figures and Tables

# Executive Summary

## Our decision is to approve a staging project from Transpower

X1 This paper sets out our decision to approve the first staging project (**Stage 1**) of a staged major capex project (**Project**) proposed by Transpower New Zealand Limited (**Transpower**).[1] The paper:

X1.1 summarises Transpower's major capex proposal for Stage 1 (**MCP**);

X1.2 outlines the submissions and cross-submissions we received in our consultation on our draft decision to approve Stage 1 (**draft decision**) and discusses how we have had regard to them in making our decision; and

X1.3 sets out our evaluation of, and decision to approve, Stage 1, together with the reasons for our decision.

X2 The MCP – the 'Waikato and Upper North Island Voltage Management – Major Capex Proposal'[2] – seeks our approval to recover the costs of grid investment for Stage 1 in the Waikato and the Upper North Island (**WUNI**) region to maintain voltage stability in the region.

X3 Transpower submitted the MCP on 13 December 2019. Under the *Transpower Capital Expenditure Input Methodology Determination 2012* [2012] NZCC 2 (**Capex IM**), Transpower may only recover capital expenditure relating to a staging project if we have first approved it.[3] Our approval regime under the Capex IM aims to strike the right balance between allowing stakeholders to scrutinise individual major capex projects, providing scope for other parties to provide alternative solutions, and enabling Transpower to undertake investment that promotes the long-term benefit of its consumers.[4]

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1 Under clause 1.1.5(2) of the Capex IM:
- a 'staging project' is a project within a major capex project (staged); and
- a 'major capex project (staged)' is a major capex project consisting of two or more staging projects; and
- 'major capex' is expenditure that:
  - (a) is incurred to meet the grid reliability standards or provide a net electricity market benefit;
  - (b) is forecast to have an aggregate capital cost exceeding $20 million, which is the base capex threshold defined in the Capex IM; and
  - (c) is not asset replacement, asset refurbishment, business support, or information system and technology assets.

2 Transpower, *Waikato and Upper North Island Voltage Management – Major Capex Proposal* (the MCP), December 2019, available at: https://www.transpower.co.nz/waikato-and-upper-north-island-voltage-management-investigation.

3 Clause 3.3.2(2) of the Capex IM.

4 Commerce Commission, *Transpower Capital Expenditure Input Methodology Reasons Paper* (**2012 Capex IM reasons paper**), 31 January 2012, at paras 2.5.12 to 2.5.13, available at: https://comcom.govt.nz/__data/assets/pdf_file/0028/63883/Capex-IM-Final-Reasons-Paper-31-January-2012.pdf.

X4 On 16 June 2020, we issued for consultation our draft decision approving Stage 1.[5] We have considered relevant matters submitters raised in our consultation and in this paper set out our decision to approve Stage 1.

## The MCP relates to maintaining voltage stability in the WUNI region

X5 The MCP seeks our approval to invest $143.0 million in two dynamic reactive devices (**DRDs**) and a post-fault demand management scheme (**post-fault DMS**) as Stage 1 to maintain voltage stability in the WUNI region. For the same reason, the MCP also seeks our approval at Stage 1 to incur the costs of preparatory works to enable the procurement and installation of series capacitors in stage 2 of the Project (**Stage 2**). Transpower intends to submit a further major capex proposal for Stage 2 when this investment is needed.

X6 Transpower considers, and we agree, Stage 1 is needed because Transpower's studies show that, during periods of high demand, there are risks of widespread interruptions to supply due to large fluctuations in voltages in the transmission network. Such fluctuation in voltages can occur after an unplanned disconnection of a major component from the transmission network when the two 250 MW-Rankine generation units at Huntly Power Station (**Rankines**) are not in service during periods of high demand. An increase in peak electricity demand in the WUNI region could exacerbate voltage stability issues and risks under the above operating conditions.[6]

X7 The other, more significant driver of the investment need for Stage 1 is the effects on voltage stability in the WUNI region that could occur if Genesis Energy Limited (**Genesis**) removes the Rankines from normal service. Genesis has not announced its position on the Rankines' future, and in its submission on our draft decision, advised that the ongoing management of the Rankines will continue based on market conditions and expected market developments.[7] However, Transpower prepared and submitted the MCP on the basis of Genesis retiring the Rankines, without replacement, by the end of 2022.[8]

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5 The draft decision is available at: https://comcom.govt.nz/__data/assets/pdf_file/0030/218676/WUNIVM-major-capex-proposal-Draft-decision-and-reasons-paper-16-June-2020.pdf.

6 As we set out in paragraphs B63 of B69 Attachment B, we consider Transpower's demand forecast is consistent with those set out in the Ministry of Business, Innovation and Employment's (**MBIE**) latest Electricity Demand and Generation Scenarios published in July 2019 (**EDGS**).

7 Genesis, *Re: Draft decision and reasons on Stage 1 of Transpower's Waikato and Upper North Island Voltage Management staged major capex project*, 9 July 2020, at pg. 1.

8 MCP, above n 2, at para 2.3. We note that Transpower also states at pg. 12 of the MCP that if a significant generation commitment – whether to Rankine life extension or to new generation – is made then Transpower will either seek an amendment to the MCP (if our decision on approval is still pending), or, if necessary, seek an amendment to the approved staging project to reflect a revised preferred option.

X8 Since issuing our draft decision on Stage 1, Rio Tinto announced on 9 July 2020 that it will close Tiwai Point aluminium smelter (**Smelter**) by August 2021.[9] For the reasons we outline in this paper,[10] we consider that this announcement, combined with other recent market activities that we discuss, increases the likelihood of the Rankines' removal from normal service, reducing some of the uncertainty associated with the need for Stage 1. Our assessment shows that this is likely to happen once approximately 500 MW of additional generation can be transmitted into the WUNI region.

X9 The main benefit of approving Stage 1 is that it will ensure the transmission network has enough capacity to supply consumers in the WUNI region and to manage voltage stability effectively as demand grows and if the Rankines are removed from normal service. Without the Stage 1 investment, there would either be a need for rolling power cuts during times of high electricity usage or a heightened risk of the North Island power system collapsing.

## Our role is to evaluate and decide whether to approve Stage 1

X10 We must evaluate a staging project Transpower submits to us against the criteria and requirements of the Capex IM for major capex projects and make a decision on whether to approve or decline it.[11] Before making a decision on a staging project, we must consult and take account of interested parties' views on our decision.[12]

X11 If we approve a staging project, as part of our decision, we must determine for the project:[13]

X11.1 a major capex allowance (**MCA**);[14]

X11.2 a major capex incentive rate;[15] and

X11.3 exempt major capex.[16]

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9 Hamish Rutherford, *Rio Tinto announces plans to close New Zealand aluminium smelter in 2021*, The New Zealand Herald, (online ed, Auckland, 9 July 2020), available at: https://www.nzherald.co.nz/business/news/article.cfm?c_id=3&objectid=12346671.

10 We analyse the potential impact of recent market activities on Stage 1 investment need and need date from paragraph B70 of Attachment B.

11 Clause 3.3.5(1) and (4) of the Capex IM. These provisions apply if we do not reject the MCP under clause 3.3.4 of the Capex IM.

12 Clause 3.3.5(5)(a) of the Capex IM.

13 Clause 3.3.5(7) of the Capex IM.

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

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

16 Under clause 1.1.5(2) of the Capex IM, '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 a major capex project or staging project, as we determine under clause 3.3.5(7) of the Capex IM.

X12 After evaluating Stage 1 against the requirements of the Capex IM, we issued our draft decision to approve Stage 1. This included determining in draft the components for Stage 1 listed in the paragraph above.

## Our decision is to approve Stage 1

### We consulted on our draft decision and have considered the submissions and cross-submissions we received

X13 We sought submissions from interested parties on our draft decision and cross-submissions on those submissions made to us. We received five submissions on our draft decision and then four cross-submissions on the submissions themselves.[17]

X14 In making our decision, we have considered relevant matters included in the submissions and cross-submissions. We summarise in this paper the submissions and cross-submissions we received and refer to and draw on matters raised in them in explaining our decision. We thank all stakeholders for their valuable contributions to our decision-making process and consider our decision is better for them.

### Our decision promotes the purpose of Part 4 of the Commerce Act 1986 and enables Transpower to deliver the right investment at the right time

X15 For the reasons we set out in this paper, we consider Stage 1 represents the investment option with the highest expected net electricity market benefit under the investment test in Schedule D of the Capex IM.[18] Further, by enabling Transpower to deliver the right investment at the right time, our decision promotes the long-term benefit of Transpower's consumers – and the purpose of Part 4 of the Commerce Act 1986 (**Act**) – by ensuring Transpower provides services at a quality that reflects their consumers' demands.[19]

X16 The detailed analysis, reasons, and Capex IM criteria underpinning our decision are set out in Attachments A to E of this paper.

### The components of our decision

X17 As part of our decision, we approve:

X17.1 an MCA of $143.0 million (in 2022/23 prices);

17 All submissions and cross-submissions can be viewed on our website: https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-transmission/transpower-capital-investment-proposals/transpower-major-capital-proposal/waikato-and-upper-north-island-voltage-management.

18 We assess Transpower's application of the investment test in Attachment D.

19 Section 52A(1)(b) of the Act. The purpose of Part 4 is set out in section 52A of the Act. Our analysis of how the MCP promotes the purpose of Part 4 of the Act is set out in Attachment B of this paper. In their submissions on our draft decision, Meridian Energy Limited (**Meridian**) endorsed our conclusion on the MCP and the purpose of Part 4. Similarly, Vector Limited (**Vector**) agreed with us that whether the MCP promotes Part 4 of the Act depends on the timing of the project.

X17.2 a major capex incentive rate of 15%, which is the default incentive rate that we consider is appropriate for Stage 1; and

X17.3 exempt major capex of $7.9 million which we consider reflects the amount of the MCA that is subject to high levels of uncertainty and which is therefore outside Transpower's reasonable control. The uncertainty allowance also includes price risks due to the potential impact of Covid-19 on costs.[20]

X18 Under our decision:

X18.1 the approved major capex outputs for Stage 1 are:

X18.1.1 one dynamic reactive device in the Upper North Island capable of delivering (within 10%) 150 Mvar capacitive to 150 Mvar inductive at nominal voltage;

X18.1.2 one dynamic reactive device in the Waikato capable of delivering (within 10%) 150 Mvar capacitive to 150 Mvar inductive at nominal voltage;

X18.1.3 a post-fault demand management scheme for the Waikato Upper North Island region; and

X18.1.4 preparatory works for Stage 2, including additional investigation, consultation, obtaining property rights and environmental approvals, design work and non-binding tendering for future series capacitors and installation works on the Brownhill-Whakamaru 1&2 transmission lines (**BHL-WKM lines**); and

X18.2 the approval expiry date is 31 December 2029.[21]

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20 We provide more details on exempt major capex and sources of uncertainty in the Project at paragraphs C67 to C68 and C79 to C82 of Attachment C.

21 See Attachment C for further detail on how we have given effect to the approval expiry date specified by Transpower.

## Transpower is considering a non-transmission solution

### Transpower considered scope for different NTSs in preparing the MCP

X19 In our consultation, Genesis,[22] the Major Energy Users' Group (**MEUG**),[23] and Vector[24] raised questions and concerns in their submissions about Transpower's consideration of non-transmission solutions[25] (**NTSs**) in developing the MCP – particularly in light of the recent market activities and accompanying uncertainty concerning demand and supply.[26]

X20 We consider that the industry and market landscape is changing and the questions raised by Genesis, MEUG, and Vector are prudent ones. However, we also consider Transpower applied itself in seeking NTS proposals and analysing at length the scope for NTSs to meet the Stage 1 investment need.

X21 Transpower sought to respond to the questions and concerns in its cross-submission. Transpower advised that, in response to the NTS request for information (**RFI**) it issued on 2 October 2019, it received only one response that met the performance requirements and had the potential to economically replace one of the dynamic reactive devices. Transpower stated that:[27]

X21.1 it is currently undertaking a formal procurement process for the above NTS option;

X21.2 it expects to receive firm pricing and agree terms for the NTS in September, at which point Transpower will make a final assessment against the Upper North Island DRD; and

X21.3 if, following our decision, Transpower finds that the NTS is the better of the two options under the Capex IM criteria, Transpower will apply to us for a major capex output amendment.

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22 Genesis, above n 7, at pg. 1.

23 MEUG, *Draft decision on Stage 1 of Waikato and Upper North Island Voltage Management staged major capex project Upper Waitaki Line Project*, 9 July 2020, at pg. 1.

24 Vector, *Draft decision on Stage 1 of Waikato and Upper North Island Voltage Management staged major capex project*, 9 July 2020, at pg. 1.

25 Under clause 1.1.5(2) of the Capex IM, a 'non-transmission solution' means an alternative to an investment in the grid, which is used by Transpower:
(a) avoid or defer a transmission investment where the transmission investment would be major capex; or
(b) manage operational risks due to unavailability of grid assets during a major capex project.

26 We analyse the Stage 1 need date in Attachment B and the potential impact of recent market activities on Stage 1 investment need and need date from paragraph B70 of Attachment B.

27 Transpower, *Cross-submission Major Capex Project draft decision: Waikato and Upper North Island Voltage Management Major Capex Proposal – Stage 1*, 17 July 2020, at pg. 2.

X22 More recently, Transpower also confirmed it is investigating the feasibility of using grid-scale batteries to provide voltage support services as an NTS to meet some of the investment need for Stage 1.[28] Transpower advises that any procurement of battery services would be conducted via an open and transparent procurement process.

X23 Meridian and Contact Energy Limited (**Contact**) recently announced they are pursuing the development of a 100-MW grid-scale battery system in the North Island. The two generator-retailers' main objective for the battery system is to provide instantaneous reserves in the North Island to enable increased northward electricity transfer via the HVDC after the Smelter closes. The generator-retailers also indicated they were exploring the scope for the battery system to provide voltage support services to Transpower to meet some of the Stage 1 investment need. [29]

X24 Having made our decision, we are assured by Transpower's commitment to applying to us for an amendment to the approved major capex project outputs if the NTS it is considering proves a better solution under the Capex IM than the DRD.[30, 31] We expect Transpower to take the same approach if it reaches a similar conclusion in respect of the scope for grid-scale batteries to meet some of the investment need for Stage 1. In both cases, we would test Transpower's application against the requirements of Part 6 and Division 2, Schedule H of the Capex IM, which include testing the amendment's key assumptions and implications for the investment test.

X25 While Transpower's NTS evaluation is ongoing, we consider it prudent to make our decision on Stage 1 at this point because:

X25.1 the Capex IM requires us to evaluate and decide Stage 1 based on the MCP that Transpower has submitted to us – which is the focus of our decision. If Transpower subsequently identifies an NTS is the better solution, then the appropriate mechanism for testing this under the Capex IM is via a major capex output amendment application;[32]

X25.2 to meet the 30-month delivery timeframe estimated by Transpower to meet the investment need by the need date under the MCP,[33] work needs to begin this year;[34] and

X25.3 as we outline at paragraph X29 below and from paragraph B70 of Attachment B, recent market activities have possibly strengthened the investment need for Stage 1.

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28 Steve Rotherham, *Big battery to boost interisland transmission*, Energy News, (27 August 2020), available at: https://www.energynews.co.nz/news-story/grid-scale-batteries/56475/big-battery-boost-interisland-transmission).

29 Steve Rotherham, above n 28.

30 Transpower, above n 27, at pg 2.

31 Clause 3.3.6(1)(c) of the Capex IM.

32 See clause 3.3.6(1)(c), Part 6, clause 7.4.2(3)(b), and Division 2, Schedule H of the Capex IM.

33 MCP, above n 2, at para 3.2.2.1.

34 We discuss and analyse the delivery timeframe and the need date for Stage 1 at Attachment B.

## Impact of Covid-19 and other recent market activities on our decision

### Covid-19

X26 In making our decision on the MCP, we have applied the criteria and followed the requirements of the Capex IM. In doing this, we analysed in our draft decision Covid-19's potential implications for the Project, and particularly, for our evaluation of and decision on Stage 1.

X27 Having considered submitters' views, we remain of the view that, while Covid-19 adds some uncertainty relating to the WUNI region's demand forecast, the added uncertainty is unlikely to change the investment need for Stage 1. As we outline in paragraph X29 below, this is primarily due to recent market activities increasing the likelihood of the Rankines' removal from normal service.

X28 We acknowledge MEUG's submission that it is less confident that Covid-19 will have little effect on forecast demand growth for the next 5 to 10 years.[35] If peak demand in the WUNI region drops to below Transpower's voltage stability limit, then Stage 1 can be deferred. The effect of a significant drop in demand would be the same as deferring the removal of the Rankines from normal service. As indicated in Transpower's sensitivity studies, it would be beneficial in such circumstances to defer the delivery date of certain major capex projects outputs for Stage 1.[36]

### Other recent market activities

X29 We also discuss in this paper the potential impact on the investment need and need date for Stage 1 of other recent market activities that occurred after we issued our draft decision, including:[37]

X29.1 Rio Tinto's announcement on 9 July 2020 that it will close the Smelter by August 2021. Recently, however, there have been indications that the Smelter may be open to negotiating a 'longer staged exit' that would defer the closure to beyond August 2021;[38]

X29.2 on 30 June, Transpower's announcement that it will deliver two further lines upgrades for the Clutha Upper Waitaki Lines Project (**CUWLP**);[39] and

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35 MEUG, above n 23, at pg. 1.

36 MCP, above n 2, at pgs. 35 to 36.

37 We discuss and analyse the potential impact of recent market activities on Stage 1 investment need and need date from paragraph B70 of Attachment B.

38 Marc Daalder, *Rio Tinto open to 'longer staged exit' for smelter*, 1 September 2020, Newsroom, available at: https://www.newsroom.co.nz/rio-tinto-open-to-longer-staged-exit-for-smelter.

39 Completing the two additional lines upgrades for CUWLP will alleviate a transmission constraint in the lower South Island and allow more hydrogeneration from Central Otago and Southland to be transported north to load centres via the HVDC – particularly in light of Rio Tinto's stated intention of closing the Smelter, which accounts for up to 13% of national electricity demand.

We understand that:

X29.3 on 10 July, Meridian announced it was looking at installing a 100-MW battery system in the North Island to provide instantaneous reserves for when the Smelter closes next year.[40] Contact subsequently advised it too was considering investing in a 50 to 100-MW battery system in the North Island for the same purpose.[41] The two generator-retailers have most recently indicated that the battery system could be a joint initiative with a capacity of 100MW and potentially scope to provide voltage support services to Transpower to meet some of the Stage 1 investment need;[42] and

X29.4 two further large, grid-connected industrial load customers in the WUNI region, New Zealand Steel Limited (**NZ Steel**) and the New Zealand Refining Company Limited (**Refining NZ**), comprising two percent of New Zealand's electricity demand, are undergoing strategic reviews regarding their ongoing operations.[43]

X30 For the reasons we discuss in Attachment B, our overall conclusion is that:

X30.1 these recent market activities make the Rankines' removal from normal service more likely, strengthening the need for Stage 1; and

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- when intact, the grid currently constrains peak generation at Manapouri and Clutha to around 1450 MW during summer peaks and 1550 MW during winter peaks –below the approximately 1800 MW of peak generation capacity that exists in the region; and
- certain outages on the grid further constrain the export of electricity from this region and limit peak Manapouri and Clutha generation to around 1010 MW during summer and 1050 MW during winter. The outages typically occur on the following circuits: CYD_ROX, CYD_CML_TWZ, NSY_ROX, and LIV_NSY. A conservative calculation is that relevant outages are in effect for three weeks of every year on average.

(see Meridian, submission on *Clutha Upper Waitaki Lines Project: Proposal to progress remaining works*, 28 May 2020, at pg. 3, available at: https://www.transpower.co.nz/sites/default/files/uncontrolled_docs/Meridian%20submission%20CUWLP%202020.pdf.). Before 6 August 2020, Transpower's position was that it would take three summers to complete CUWLP. However, on that date, Transpower announced there is scope to fast-track the delivery of CUWLP by a year with a new completion date of May 2022 (See Steve Rotherham, *CUWLP deadline now May 2022*, Energy News, (6 August 2020), available at: https://www.energynews.co.nz/news-story/electricity-transmission/55436/cuwlp-deadline-now-may-2022?utm_source=newsletter&utm_medium=email&utm_campaign=energy-news-newsletter).

40 Eamon Rood, *Meridian eyes North Island battery storage*, Energy News, (10 July 2020), available at: https://www.energynews.co.nz/news-story/electricity/53998/meridian-eyes-north-island-battery-storage.

41 Steve Rotherham, *Gas, pumped hydro or batteries for dry years?*, Energy News, (17 August 2020), available at: https://www.energynews.co.nz/news-story/natural-gas/55985/gas-pumped-hydro-or-batteries-dry-years?utm_source=/news-story/natural-gas/55985/gas-pumped-hydro-or-batteries-dry-years&utm_medium=recent_comments&utm_campaign=fm.

42 Steve Rotherham, above n 28. As noted above at paragraph X22, Transpower has advised that any procurement of battery services as an NTS would be conducted via an open and transparent procurement process.

43 NZ Steel draws most of its electricity from its cogeneration plant, but it also uses about 440 GWh per year of electricity from the grid. Refining NZ draws about 341 GWh/year from the grid. See: Bernie Napp, *NZ Steel's future on the line*, (17 August 2020), Energy News, available at: https://www.energynews.co.nz/news-story/steel/56026/nz-steels-future-line; Eamon Rood, *Big loss for refinery, major changes ahead*, Energy News, (17 August 2020), available at: https://www.energynews.co.nz/news-story/oil-refining/56030/big-loss-refinery-major-changes-ahead; and; Steve Rotherham, *Demand destruction curbing power prices; more to come?*, Energy News, (17 August 2020), available at: https://www.energynews.co.nz/news-story/electricity-demand/56170/demand-destruction-curbing-power-prices-more-come.

X30.2 there is not enough information to conclude that these market activities will bring forward the need date for Stage 1. This is because the detailed supply and demand dynamics of these activities, and their implications for the wholesale market, remain uncertain. This makes it difficult at this point to conclude with certainty that Stage 1's need date will be brought forward.

X31 For the reasons we outline in Attachments B and C of this paper, we remain of the view that it is appropriate to allow for uncertainty relating to Covid-19 and these other market activities in setting the MCA and exempt major capex for Stage 1.[44] This would accommodate potential increases in equipment costs and labour costs relating to extra health and safety precautions and delays in delivering Stage 1.

[44] If we approve a major capex project, we determine the MCA and any exempt major capex for it under clause 3.3.5(7)(a) and (c) of the Capex IM.

# Introduction

## Purpose of this paper

1 The purpose of this paper is to set out and explain our decision to approve Stage 1.

## How we have structured this paper

2 The body of this paper:

2.1 provides an overview of our decision-making framework under the Capex IM, the MCP, and the draft decision we issued on 16 June;

2.2 outlines our decision to approve Stage 1; and

2.3 summarises the submissions and cross-submissions from our consultation on our draft decision and how we have had regard to them.

3 Attachments A to E set out the analysis, reasons, and Capex IM criteria underpinning our decision. Specifically:

3.1 Attachment A sets out our evaluation criteria under the Capex IM which comprise the general criteria,[45] specific criteria,[46] and the investment test;[47]

3.2 Attachment B provides our evaluation of the MCP against the general criteria;

3.3 Attachment C provides our evaluation of the MCP against the specific criteria;

3.4 Attachment D provides our evaluation of Transpower's application of the investment test; and

3.5 Attachment E sets out a summary and our assessment of Transpower's consultation in preparing the MCP under the Capex IM.

4 Attachments A to E refer to and draw on points from submissions and cross-submissions from our consultation. The Attachments also analyse how certain recent market activities occurring before and after we issued our draft decision impact on our decision.

5 Attachment F lists the acronyms, abbreviations and terms used in this paper.

## Regulatory approval process to date

6 A summary of our regulatory approval process for Stage 1 prior to this decision is:

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[45] Part 6 of the Capex IM.

[46] Schedule C of the Capex IM.

[47] Schedule D of the Capex IM.

6.1 On 27 May 2016, Transpower notified us under clause 3.3.1(1) of the Capex IM of its plan to develop an MCP for the Project.

6.2 In July 2016, Transpower consulted with stakeholders on its long list of options to meet the investment need[48] (**long-list consultation**)[49] and invited information on NTSs from interested parties as required by Schedule I of the Capex IM.

6.3 In June 2019, Transpower consulted on its short list of investment options (**short-list consultation**)[50] as required by Schedule I3 of the Capex IM.

6.4 On 2 October 2019, Transpower issued a second RFI on NTSs. In the second RFI, Transpower clarified the capacity and performance it would need from an NTS to meet the need of Stage 1.

6.5 On 13 December 2019, Transpower submitted the MCP to us for our approval of the proposed investment.[51]

6.6 On 16 June 2020, we invited submissions on our draft decision to approve Stage 1 and cross-submissions on submissions provided.

48 Under clause 1.1.5(2) of the Capex IM, 'investment option' means a technically feasible solution, including an NTS, designed to facilitate or meet a specific investment need, other than an option fully funded under a new investment contract.

49 Transpower, *Waikato and Upper North Island voltage management long-list consultation* (**long-list consultation document**), July 2016, available at: https://www.transpower.co.nz/sites/default/files/projects/resources/Waikato%20and%20Upper%20North%20Island%20Voltage%20Management%20long-list%20consultation_2.pdf.

50 Transpower, *Waikato and Upper North Island voltage management investigation – consultation on short list of investment options* (**short-list consultation document**), June 2019, available at: https://www.transpower.co.nz/sites/default/files/projects/resources/WUNIVM%20Short-list%20Consultation%20-%20June%202019.pdf.

51 Under clause 1.1.5(2) of the Capex IM, a 'proposed investment' is the investment option Transpower submits as an MCP to us for approval of a major capex project or, where it is a staged major capex project (as is the case in this MCP), approval of a staging project.

# Our decision-making framework

## Purpose of this section

7 This section provides an overview of the decision-making framework we have applied in reaching our decision on Stage 1.

## Our decision-making framework

### Capex IM

8 Regulation under Part 4 of the Act (**Part 4**) seeks to promote the long-term benefit of consumers of regulated services.[52] These regulated services include electricity transmission services provided by Transpower.

9 The input methodologies (**IMs**) under Part 4 are the upfront rules, processes, and requirements of Part 4 regulation. Their purpose is to promote certainty for suppliers and consumers in relation to the rules, requirements and processes applying to regulated services under Part 4.[53] The IMs apply to electricity transmission services provided by Transpower.

10 One of the IMs that applies to Transpower is the Capex IM.[54] The two major functions of the Capex IM are to provide for the scrutiny of Transpower's proposed and actual investments and to incentivise Transpower to deliver those investments efficiently.

### Major capex projects

11 Under clause 3.3.2(2) of the Capex IM, Transpower may only recover its costs relating to a major capex project, or (as is the case here) a staging project of a staged major capex project, if we have first approved it.[55]

12 Transpower may submit a major capex proposal for a staging project to us at any point during a regulatory period.[56] If we do not reject the major capex proposal,[57] we must either:[58]

12.1 approve the staging project; or

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52 Section 52A of the Act.

53 Section 52R of the Act.

54 Along with the Capex IM, Transpower is subject to the *Transpower Input Methodologies Determination 2010* [2012] NZCC 17 (**Transpower IMs**), which sets out IMs for: cost allocation, asset valuation, treatment of taxation, cost of capital, specification of price, the incremental rolling incentive scheme, and reconsideration of the price-quality path.

55 As this major capex proposal is for a staging project, in describing our decision-making framework in this section, we will refer to staging projects rather than major capex projects.

56 Clause 3.3.3(1) to (3) of the Capex IM.

57 Under clause 3.3.4 of the Capex IM, we may reject an MCP if it does not comply with the requirements in clause 7.4.1, or if Transpower has not complied with the requirements specified in clause 3.3.1 of the Capex IM.

58 Clause 3.3.5(1)(a) and (b) of the Capex IM.

12.2 decline the staging project.

13 If we approve a staging project, we must also determine the MCA,[59] major capex incentive rate,[60] and any exempt major capex.[61]

14 Before we can approve or decline a staging project, we must:

14.1 publish the relevant major capex proposal;[62]

14.2 evaluate the major capex proposal in accordance with the evaluation criteria in the Capex IM, including any further information we have received in the evaluation process;[63] and

14.3 consult in the following ways:[64]

14.3.1 make and publish a draft decision on the major capex proposal;

14.3.2 seek written submissions from interested persons on anything published; and

14.3.3 seek the written views of interested persons on those submissions.

15 We must evaluate a major capex proposal against three sets of evaluation criteria in the Capex IM:

15.1 the general evaluation criteria for capital expenditure in Part 6;

15.2 the specific evaluation criteria for MCPs in Schedule C;[65] and

15.3 the investment test in Schedule D, Division 1.[66]

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[59] Clause 3.3.5(7)(a) of the Capex IM.

[60] Clause 3.3.5(7)(b) of the Capex IM.

[61] Clause 3.3.5(7)(c) of the Capex IM.

[62] Clause 8.1.1(1)(a) of the Capex IM.

[63] Clause 3.3.5(5)(b)(i)-(ii) of the Capex IM.

[64] Clauses 3.3.5(5)(a) and 8.1.1(1)(a)(ii) to (iv) of the Capex IM.

[65] Under clause 6.1.1(4) of the Capex IM, as part of that Part 6 criteria, we must also evaluate a major capex proposal in accordance with the specific criteria for major capex proposals in Schedule C of the Capex IM.

[66] Under clause C1(1) of Schedule C of the Capex IM, we must evaluate whether the investment proposed in the major capex proposal satisfies the investment test specified in Schedule D, Division 1 of the Capex IM.

# Overview and background to the MCP

## Purpose of this section

16 The purpose of this section is to provide background on the MCP. The section covers:

16.1 what major capex projects (and staging projects) are under the Capex IM; and

16.2 the content of, and background to, the MCP.

## Major capex projects under the Capex IM

### Major capex projects

17 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 an NTS".[67] Major capex covers capital expenditure for large individual transmission grid enhancement projects that, given their nature and magnitude, warrant individual scrutiny and public consultation.[68] Specifically, under clause 1.1.5(2) of the Capex IM, 'major capex' means expenditure that:

17.1 is incurred to meet the grid reliability standards (**GRS**)[69] or provide a 'net electricity market benefit';

17.2 is forecast to have an aggregate capital cost exceeding the base capex threshold of $20 million;[70] and

17.3 is not incurred in relation to asset replacement, asset refurbishment, business support or information system and technology assets.

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[67] Clause 1.1.5(2) of the Capex IM.

[68] Commerce Commission, *Transpower capex input methodology review - Decisions and reasons* (**2017/18 Capex IM review reasons paper**), 29 March 2018, at para 54, available at: https://comcom.govt.nz/__data/assets/pdf_file/0033/79926/Transpower-capex-IM-review-Decisions-and-reasons-29-March-2018.PDF.

[69] Under clause 1.1.5(2) of the Capex IM, the GRS are defined as standards developed under the Electricity Industry Participation Code 2010 (**Code**) for the reliability of the grid. Under clause 12.56 of the Code, the purpose of the GRS is to provide a basis for Transpower and other parties to appraise opportunities for transmission investments and transmission alternatives. The deterministic limb (or N-1 criterion) of the GRS is set out at clause 2(2)(b) of Schedule 12.2 of the Code (**N-1 criterion of the GRS**) and provides that with all assets that are reasonably expected to be in service, the power system would remain in a satisfactory state during and following the tripping of one of the transmission assets in the core grid.

[70] Under clause 3.3.3(2) of the Capex IM, while the aggregate forecast capital expenditure for the Project (comprising all staging projects) must exceed the base capex threshold of $20 million, the forecast expenditure for Stage 1 itself does not need to exceed this threshold.

18 As is the case here, a major capex project may also be 'staged': Transpower can split a major capex project into several staging projects[71] if Transpower considers that staging would allow it and us to:[72]

18.1 set a more accurate level of funding for the project; and/or

18.2 better manage uncertainties in need and timing of the project.

19 Clause 3.3.3(2) of the Capex IM requires Transpower to submit a major capex proposal to us when it seeks approval for one or more staging projects of a staged major capex project.

20 If Transpower seeks approval for one or more staging projects, the aggregate forecast capital expenditure and forecast maximum recoverable costs for all the staging projects that comprise the staged major capex project must exceed $20 million.[73]

21 The Capex IM also sets out the information that Transpower needs to provide in its MCP and the associated certification of the information it provides.[74] The CEO of Transpower must certify that the information provided accurately represents the Transpower's operations. The CEO certification must also state that the proposed investment was approved according to Transpower's director and management approval policies.[75]

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71 This is called a 'major capex project (staged)' and is defined in clause 1.1.5(2) of the Capex IM.

72 *2017/18 Capex IM review reasons paper*, above n 68, at para 244.

73 Clause 3.3.3(2)(a) of the Capex IM. Under clause 3.3.3(2)(b), for each staging project for which Transpower seeks approval, the forecast capital expenditure and forecast maximum recoverable costs does <u>not</u> need to exceed $20 million.

74 Clause 7.4.1 and Schedule G of the Capex IM.

75 Clause 9.2.1 of the Capex IM.

### What happens if we approve a staging project

22 Under clause 2.2.3(2)(f) of the Transpower IMs, if we approve a staging project, Transpower may, after commissioning the assets for the relevant staging project, include the actual costs of the assets in its regulatory asset base. Transpower may then recover those costs under the *Transpower Individual Price-Quality Path Determination 2020* [2019] NZCC 19 (**IPP**) [76] as transmission charges allocated according to the transmission pricing methodology (**TPM**).[77]

23 Under clause 7.5.1(1)(c) of the Capex IM, Transpower has provided an estimate based on the existing TPM of the increase in transmission charges from the expenditure relating to Stage 1.[78] We note that the Electricity Authority recently completed its review of the TPM and issued new TPM guidelines to Transpower.[79] Transpower must use the new TPM guidelines to develop a proposed new TPM[80] to submit to the Electricity Authority by 30 June 2021 for its approval.[81]

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76 Clause 8 of the IPP, available at: https://comcom.govt.nz/__data/assets/pdf_file/0034/188782/Transpower-Individual-Price-Quality-Path-Determination-2019-2020-NZCC-19-14-November-2019.PDF. We note that:

a) any incentive amounts arising from Stage 1 will be determined as part of calculating the major capex expenditure and output adjustment under clause B3(1) of Schedule B of the Capex IM and, under clause 31.1.3(h) of the IPP, will enter Transpower's EV account and roll over to affect Transpower's maximum allowable revenue at the next regulatory control period; and

b) under clause 8.3.2 of the IPP, major capex we approve becomes part of the maximum revenue that Transpower may recover for electricity transmission services in a pricing year by the Commission reconsidering the IPP under clause 3.7.4(4) of the Transpower IMs.

77 The TPM is the methodology by which Transpower prices its transmission services developed in accordance with subpart 4 of Part 12 of the Code and specified in Schedule 12.4 of the Code.

78 MCP, *Attachment F – Spreadsheet of pricing by GXP and GIP*, 13 December 2019, available at: https://comcom.govt.nz/__data/assets/excel_doc/0036/196947/Transpower-WUNIVM-major-capex-proposal-Attachment-F-Spreadsheet-of-pricing-by-GXP-and-GIP-13-December-2019.xlsx.

79 See Electricity Authority website, Transmission Pricing Review, Development, TPM decision and guidelines, available at: https://www.ea.govt.nz/development/work-programme/pricing-cost-allocation/transmission-pricing-review/development/tpm-decision-and-guidelines/.

80 Under clause 12.89(1) of the Code, Transpower must develop its proposed TPM consistent with—

(a) any determination made under Part 4 of the Commerce Act 1986; and
(b) the Authority's objective in section 15 of the Act; and
(c) any TPM guidelines the Electricity Authority publishes under clause 12.83(b).

81 Under clause 12.88(1) of the Code, Transpower must submit a proposed new TPM to the Electricity Authority within 90 days (or a longer period that the Electricity Authority specifies) of a written request from the Electricity Authority. In its decision paper on the new TPM guidelines, the Electricity Authority directed Transpower to submit a proposed new TPM by no later than 30 June 2021 – see Electricity Authority, *Transmission pricing methodology 2020 Guidelines and process for development of a proposed TPM*, 10 June 2020, at Executive Summary pg.V, available at: https://www.ea.govt.nz/dmsdocument/26851-tpm-decision-paper. Transpower is underway in its TPM development process and has made the following webpage to keep stakeholders updated: https://www.transpower.co.nz/industry/transmission-pricing-methodology-tpm.

24 Under the new TPM guidelines, the new TPM that Transpower develops will classify Stage 1 as a 'benefit-based investment' to which a benefit-based charge will apply.[82] The allocation of transmission charges for Stage 1 under the new TPM (when the Electricity Authority approves it) is therefore likely to differ to that set out in Transpower's estimate under clause 7.5.1(1)(c) of the Capex IM.[83, 84]

## Background to the MCP

### The investment need – voltage management in the WUNI region

25 In the MCP, Transpower states that the investment need is to maintain voltage stability in the WUNI region.[85]

26 This need has arisen from actual and announced decommissioning of major generation plant in the WUNI region, with a reduction of over 1000 MW of generation since 2012, as well as actual and forecast electricity demand growth in the region. Transpower considers this represents a significant change to the New Zealand power system, with significant voltage management implications for the WUNI region.

27 Specifically, Transpower considers that the following four factors underpin the investment need for Stage 1:

27.1 thermal generation decommissioning;

27.2 voltage stability – both undervoltage and overvoltage;

27.3 future load growth in the region; and

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82 Electricity Authority, *Transmission pricing methodology 2020 Guidelines*, 10 June 2020, at clauses 13 and 14 and at clause 69 definition of 'post-2019', available at: https://www.ea.govt.nz/dmsdocument/26850-tpm-2020-guidelines.

83 To avoid doubt, the new TPM guidelines and the new TPM developed under them will not affect the regulatory approval process for Stage 1 under the Capex IM or the amount Transpower can recover in transmission charges for Stage 1. We also note that Transpower's estimate under clause 7.5.1(1)(c) of the Capex IM of the increase in transmission charges from expenditure relating to Stage 1 is valid to the extent that it is based on the TPM existing and applicable at the time Transpower submitted the MCP.

84 The new TPM guidelines and TPM to be developed under them featured in submissions and cross-submissions from our consultation on our draft decision. Submitters expressed uncertainty as to the potential impact of the TPM on the MCP and our decision and sought clarification from Transpower on who the MCP's likely beneficiaries will be under the new guidelines. As we outline in our summary of submissions from paragraph 94, the allocation of transmission charges under the TPM in its current and future forms is the Electricity Authority's responsibility and is not part of the Capex IM's investment test or criteria for approving a major capex proposal. Clause 7.5.1(1)(c) of the Capex IM requires Transpower to provide with an MCP an estimate of the expected increase in transmission charges due to the proposed expenditure. We consider, however, that this requirement applies based on the current TPM, rather than the TPM which Transpower is developing under the new TPM guidelines.

85 MCP, above n 2, at pg. 7.

27.4 good electricity industry practice (**GEIP**)[86] to support investment need.

28 We discuss each of these four factors under the following four subheadings.

**Recently decommissioned generation**

29 Recently decommissioned generation plant in the WUNI region comprises:

29.1 in December 2012, Genesis placed one of the Rankines into long-term storage;

29.2 in 2015, Genesis permanently retired another Rankine;

29.3 in September 2015, Contact ceased operating the Otahuhu B combined-cycle gas power station, removing 380 MW of generation; and

29.4 in December 2015, Mighty River Power Limited (now Mercury Energy Limited (**Mercury**)) decommissioned and ceased operating the Southdown power station, removing 175 MW of generation.

30 There are two Rankines still in service, though their future is increasingly uncertain. Genesis has announced that by 2025, it will only use coal in the Rankines in abnormal market conditions. Genesis anticipates keeping the Rankines in the market until at least 2022, subject to market conditions.[87]

31 Transpower's analysis shows that, even with the remaining Rankines available for service, the power system will be at risk of voltage instability when supplying peak demand in the WUNI region from 2022 onwards if Genesis's 403 MW combined-cycle gas turbine Unit 5 generator at Huntly Power Station (**Unit 5**) is unavailable for service at that time.[88] If Transpower supplies the forecast peak demand without Unit 5 in service, and a major transmission line fails, this would create a risk of a system collapse in at least the Upper North Island.

32 We discuss in Attachment B our view that particular recent market activities make the Rankines' removal from normal service more likely, strengthening the need for Stage 1. However, as noted at paragraph X30.2, we do not consider there is enough information to conclude that these market activities will bring forward the need date for Stage 1.

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[86] Under clause 1.1.5(2) of the Capex IM, the definition of 'good electricity industry practice' is that specified in clause 1.1(1) of the Code, which is: "the exercise of that degree of skill, diligence, prudence, foresight and economic management, as determined by reference to good international practice, which would reasonably be expected from a skilled and experienced asset owner engaged in the management of a transmission network under conditions comparable to those applicable to the grid consistent with applicable law, safety and environmental protection. The determination is to take into account factors such as the relative size, duty, age and technological status of the relevant transmission network and the applicable law."

[87] MCP, above n 2, at pg. 24.

[88] Unit 5 is not a Rankine unit, and is expected to remain in service for the foreseeable future.

**Voltage stability – undervoltage and overvoltage**

33 Maintaining voltage stability involves preventing the voltage getting too high or too low.

34 Transpower expects both undervoltage and overvoltage issues to arise in the WUNI region as peak demand increases and if the Rankines are removed from normal service.[89]

35 Transpower uses voltage stability limits identified from static and dynamic modelling to inform WUNI load limits to avoid voltage instability. If the Rankines retire from normal service before the end of 2022, load growth in the region could create an undervoltage risk from winter 2023, which would increase with continued demand growth.[90]

36 The consequences of exceeding voltage stability limits could be serious; with the strong possibility of widespread voltage collapse in the grid if certain faults occur, resulting in a blackout and the need to 'black start' the grid. Transpower considers that while these faults have a low probability of occurrence, the very high economic consequences of a blackout warrant investment to mitigate this risk.[91]

37 Transpower currently considers that the likelihood of transient (ie, rapidly occurring) overvoltage risk is very low, and it is for this reason that the system operator classifies the risk as an 'Other event' in its policy statement.[92] However, Transpower considers that as further generation retires and demand grows, transient overvoltage risk will increase significantly.[93] Transpower says that this, coupled with the long lead time to install and commission additional dynamic reactive support, increases the gravity of this risk and the need to address it.

38 According to Transpower, managing the increasing potential for under and overvoltage events in the WUNI region requires either:[94]

38.1 significant generation investment or retention at or north of Huntly;

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89 MCP, above n 2, at pg. 18, Figure 2.

90 Above n 2, at pgs. 18-21 and Figure 2.

91 Above n 2, at pg. 18.

92 The system operator's policy statement is incorporated into the Code by reference under Part 8 of the Code, and is available at: https://www.ea.govt.nz/dmsdocument/24557-policy-statement-certified-policy-statement-11-january-2019.

Under clause 12.3 of the policy statement, 'Other events' are:

a) events that are considered to be uncommon and for which the impact, probability of occurrence and estimated cost and benefits do not justify implementing available controls, or for which no feasible controls exist or have been identified, other than unplanned demand shedding, AUFLS and other emergency procedures or restoration measures; or

b) events that have no impact or where no pre or post-contingent event management is required.

93 MCP, above n 2, at pg. 19.

94 Above n 2, at pg. 27.

38.2 increased fast-acting reactive support in the WUNI region; or

38.3 reduced winter peak load in the WUNI region.

39 Without investment to meet the need, Transpower's studies show that either North Island electricity consumers would be exposed to the risk of voltage collapse,[95] or the system operator would have to manage load for the WUNI region according to voltage stability limits.

**Forecast load growth in the WUNI region**

40 Transpower based its peak demand forecasts for the WUNI region on historical rates of growth combined with assumptions about emerging technologies drawn from EDGS.[96]

41 Transpower's demand modelling also captures the latest peak demand information for the WUNI region in 2018, which saw peak demand in the region grow for the second consecutive year. Since 2000, the WUNI region's peak demand has trended upwards, increasing from approximately 2060 MW in the year 2000, to 2790 MW in 2018.

42 Our draft decision analysed Transpower's peak demand forecast and its implications for the Stage 1 investment need and need date. We summarise submissions and cross-submissions on peak demand forecast, investment need and need date from paragraph 71 below. We provide our view on these matters in light of submitters' views, Covid-19, and recent market activities at Attachment B.

**GEIP supports investment**

43 Clause G5(12) of Schedule G of the Capex IM requires Transpower to include in a major capex proposal a description of how consistent with GEIP Transpower's proposed investment is.

44 For this purpose, Transpower engaged external consultants to provide technical advice to Transpower's power system modelling team on the following aspects of the MCP:[97]

44.1 Transpower's analysis of the overvoltage need. The external advice prompted Transpower to modify its modelling approach;[98] and

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95 Above n 2, *Attachment B: Power Systems Analysis Report* (**MCP power systems analysis report**), available at: https://comcom.govt.nz/__data/assets/pdf_file/0031/196951/Transpower-WUNIVM-major-capex-proposal-Attachment-B-Power-system-analysis-report-13-December-2019.pdf.

96 EDGS is available at: https://www.mbie.govt.nz/dmsdocument/5977-electricity-demand-and-generation-scenarios.

97 MCP, above n 2, at pgs. 22 to 23.

98 PSC, *Technical Opinion on Temporary Overvoltages for Transpower Final*, 1 July 2019.

44.2 Transpower's planning criteria, which the consultant found to be consistent with Transpower's international peers and GEIP.[99]

**Transpower's planning process behind the MCP**

45 On 27 May 2016, Transpower notified us of its intention to plan the Project.[100]

46 In its notification, Transpower outlined its intention to carry out the long-list consultation, focusing on:

46.1 describing the investment need;

46.2 providing information on the key assumptions to be used in its investigation, including electricity demand forecasts and generation scenarios;

46.3 providing information on the investment test parameters to be used including the calculation period, discount rate and value of expected unserved energy;

46.4 providing a draft long list of potential transmission options; and

46.5 providing an RFI regarding NTSs.

47 Transpower considered feedback on its long-list consultation, and then put together a short-list consultation document:

47.1 incorporating appropriate changes to Transpower's long list of transmission options by reducing the long list to a short list of options;

47.2 evaluating the short list using the investment test, taking account of NTSs, and identifying a preferred option;

47.3 incorporating appropriate changes to Transpower's key assumptions and investment test parameters; and

47.4 considering whether to proceed to a request for proposal for NTSs.

48 All documents Transpower provided as part of the MCP are listed in Table B1 of this paper. In addition to the MCP and its attachments, the documents include Transpower's long-list and short-list consultation documents together with additional information Transpower provided during our evaluation of the MCP.

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99 GHD Advisory, *Review and Comparison of Planning Criteria for WUNIVM Project Transpower New Zealand Limited*, 4 December 2019), at pg. 15.

100 Transpower's notification of 27 May 2016 is available at: https://www.transpower.co.nz/sites/default/files/projects/resources/wuni%20proposed%20mcp.pdf.

# Our decision is to approve Stage 1

## Overview

49 This section sets out our decision to approve Stage 1 including the components that we determine as part of the decision. The following section summarises submissions and cross-submissions from our consultation on the draft decision and outlines how we have had regard to them in coming to our decision. The reasons and analysis behind our decision – including submitters' points that we have drawn on – are set out in Attachments A to E of this paper.

50 Our decision encompassed evaluating the MCP and deciding whether to approve it.[101] In deciding to approve the MCP, as part of our decision, we also had to determine the following components:[102]

50.1 the MCA;

50.2 exempt major capex; and

50.3 the major capex incentive rate.

51 We evaluated the following components proposed by Transpower:[103]

51.1 the major capex project outputs;

51.2 the approval expiry date; and

51.3 the commissioning date assumption.

## Our decision on the MCA, major capex incentive rate, and exempt major capex for Stage 1 largely reflects our draft decision

52 Our decision includes determining the MCA, which is the capital expenditure allowance for Stage 1. If the costs for Stage 1 exceed the MCA, penalties under the major capex incentive scheme will apply. Conversely, rewards will apply under the incentive scheme if Stage 1 costs less than the MCA less exempt major capex.[104]

53 Table 1 summarises our decision on the MCA for Stage 1 and is followed by discussion on why we have reduced the MCA relative to the MCA in our draft decision.

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101 Clause 3.3.5(1) and Schedule C of the Capex IM.

102 Clause 3.3.5(7) and Schedule C of the Capex IM.

103 Clause 3.3.5(6) and clause C1(3) of Schedule C of the Capex IM.

104 Clause B3 of Schedule B of the Capex IM sets out the incentive scheme that will apply to the actual cost of delivering Stage 1. Our summary of how the scheme will apply to the MCA for Stage 1 is set out at paragraph C110 of Attachment C.

**Table 1: MCA for Stage 1 ($ million)**

| Base estimate in 2019/20 prices | P50 estimate 2019/20 prices | Inflation factors | Financing costs | MCA 2022/23 prices | Exempt major capex 2022/23 prices |
|---|---|---|---|---|---|
| 104 | 131 | 5 | 7 | 143 | 7.9 |

54 As we outline at paragraphs C22 and C23, since our draft decision, Transpower has confirmed that the DRDs it will procure following our decision will be static synchronous compensators (**STATCOMs**). This removes the uncertainty associated with the DRDs, which is reflected in the lower MCA and lower exempt major capex figures shown above in Table 1, relative to those in our draft decision.

55 In line with our draft decision under clause 3.3.5(7)(b) of the Capex IM, we have decided to set the major capex incentive rate for Stage 1 at 15%.

56 We consider that the incentive rate of 15% will incentivise Transpower to seek efficiencies in delivering Stage 1. An incentive rate of 15% (which is the default rate under the Capex IM) is appropriate for projects with an expected capital cost in the mid-range and for which most of the construction work will occur at existing substations.

57 Our draft decision under clause 3.3.5(7)(c) of the Capex IM was to set an exempt major capex amount of $35.666 million in 2019 prices or $38.869 million in 2022/23 prices. We considered this amount reflected the portion of the MCA that is subject to high levels of uncertainty.

## Under our decision, certain Stage 1 components are those specified by Transpower in its MCP

58 Under clause 3.3.5(6) of the Capex IM, the effect of our decision to approve Stage 1 is to adopt certain components for Stage 1 that Transpower specified in the MCP, being the:

58.1 major capex project outputs;

58.2 approval expiry date; and

58.3 commissioning date.

59 We outline below these components from the MCP that we approve under our decision.

### Major capex project outputs for Stage 1

60 The major capex project outputs are the specific grid outputs Transpower will deliver under Stage 1,[105] being:

60.1 one DRD in the Upper North Island capable of delivering (within 10%) 150 Mvar capacitive to 150 Mvar inductive at nominal voltage;

60.2 one DRD in the Waikato capable of delivering (within 10%) 150 Mvar capacitive to 150 Mvar inductive at nominal voltage;

60.3 a post-fault DMS for the WUNI region; and

60.4 preparatory works for Stage 2, including additional investigation, consultation, obtaining property rights and environmental approvals, design work and non-binding tendering for future series capacitors and installation works on the BHL-WKM lines.

61 The above major capex project outputs are the same as those approved in our draft decision, though we note that Transpower is seeking to establish whether the NTS option under consideration is a better solution under the Capex IM. Transpower has committed to applying to us for an amendment to the above approved major capex project outputs if, following our decision, this proves to be the case.[106]

### Approval expiry date for Stage 1

62 The approval expiry date is the date beyond which Transpower will not be able to recover costs from consumers.[107] The approval expiry date that Transpower specified in its MCP and which we approve in our decision for Stage 1 is 31 December 2029 – the same as that included in our draft decision.

### Commissioning date assumption for Stage 1

63 The commissioning date assumption is the date by which Transpower assumes the last asset of Stage 1 will be commissioned.[108] Transpower plans to deliver Stage 1 as several work packages with different forecast commissioning dates.

64 In its MCP, Transpower proposed the commissioning date for all Stage 1 assets other than the preparatory works for Stage 2 be 31 December 2022.[109] We consider this date caters for the Stage 1 investment need and need date, and, in line with our draft decision, we approve it.

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[105] Under clause 1.1.5(2) of the Capex IM, a 'grid output' is the output in respect of a particular grid output measure, which is a measure that quantifies the output or benefit (where 'benefit' may include reduction in risk) delivered by the grid, investment in the grid, or expenditure facilitating or enabling future investment in the grid.

[106] Transpower, above n 27, at pg. 2.

[107] Under clause 3.3.6(1)(d) of the Capex IM, Transpower may apply to us to amend the approved approval expiry date.

[108] Definition of 'commissioning date assumption' under clause 1.1.5(2) of the Capex IM.

[109] MCP, above n 2, at pg. 44.

# Submissions and cross-submissions from our consultation on our draft decision

65 We received a submission on our draft decision from each of Energy Trusts of New Zealand Inc. (**ETNZ**), Genesis, Meridian, MEUG, and Vector. We received a cross-submission on those submissions from each of Transpower, Vector, MEUG, and New Zealand Steel Limited (**NZ Steel**).

66 We have categorised the matters raised in the submissions and the cross-submissions as follows:

66.1 our draft decision to approve Stage 1;

66.2 investment need and need date of Stage 1;

66.3 major capex project outputs and NTSs; and

66.4 the TPM to be developed under the new TPM guidelines.

67 We summarise the submissions and cross-submissions below and discuss how we have had regard to them in making our decision. The Attachments to this paper providing the analysis and reasons underpinning our decision also refer to and draw on points from the submissions and cross-submissions.

### Submissions on our draft decision to approve Stage 1

68 Meridian supported our draft decision to approve Stage 1.[110]

69 ETNZ recommended that we approve Stage 1 but also review the methodology for allocating its costs—the TPM.[111] As touched on above,[112] reviewing, amending, and determining the TPM is the Electricity Authority's role.

70 Genesis, MUEG and Vector did not make any specific comments on our draft decision to approve Stage 1 or in relation to the components we determined in the draft decision.

### Investment need and need date of Stage 1

71 In our draft decision, we identified two drivers behind the investment need:[113]

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110 Meridian, *Draft decision on Stage 1 of Waikato and Upper North Island Voltage Management staged major capex project*, 8 July 2020, at pg. 1.

111 ETNZ, *Submission on draft decision and reasons paper for Transpower's Waikato and Upper North Island voltage management major capex proposal*, 9 July 2020, at pg. 6.

112 See above n 84. We summarise below from paragraph other submissions and cross-submissions that raised questions concerning the impact of the TPM.

113 Draft decision, above n 5, at paragraphs X6 to X8, and X20.

71.1 the primary driver – the potential removal from normal service of the Rankines; and

71.2 forecast demand growth in the WUNI region.

72 We summarise submissions and cross-submissions on each of these drivers, as follows.

*The Rankines' potential removal from normal service*

73 Genesis submitted that:[114]

73.1 it has not made any commitments regarding the Rankines' long-term operation, or potential alternative configurations of the five active generating units at the Huntly site, and cautioned against participants making large capital expenditure commitments based on an expectation of reduced generation capacity at Huntly; and

73.2 the ongoing management of the Huntly assets will continue based on market conditions and expected market developments. Should a commitment be made that results in material changes in generating capacity at Huntly, Genesis will inform the market of its plans in accordance with market disclosure requirements in the Code.

74 ETNZ suggested that we note that the primary need for the voltage support investment is due to actions on the part of North Island generators.[115]

75 Meridian submitted that there is some uncertainty regarding the Rankines' future, noting that the Stage 1 MCP assumes Genesis will remove the Rankines from normal service by 2022. Meridian noted that the closure of the Smelter could also bring forward the removal of the Rankines from normal service.[116]

76 MEUG agreed that the optimal timing for Stage 1 is when the Rankines retire but considered it uncertain as to when this will happen.[117] Vector submitted that Genesis had said the Rankines may be removed earlier than 2022 if Rio Tinto announced it will close the Smelter prior to 2022.[118]

77 In its cross-submission, Transpower:[119]

77.1 noted the Smelter's closure and the extra baseload generation capacity this will make available from Meridian's Manapouri Power Station (**Manapouri**)

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114 Genesis, above n 7, at pg. 1.

115 ETNZ, above n 111, at pg. 6.

116 Meridian, above n 110, at pg. 2.

117 MEUG, above n 23, at pg. 1.

118 Vector, above n 24, at pg. 1.

119 Transpower, above n 27, at pg. 2.

could see other changes to the wholesale electricity market – for example, removing the need for other North Island thermal baseload generation; and

77.2 expressed willingness to defer Stage 1 components if, by October 2020, Transpower finds that there is:

77.2.1 no change to Huntly generation until after winter 2023;

77.2.2 a material reduction in peak demand expectation due to Covid-19; or

77.2.3 another material market announcement affecting the investment need of Stage 1.

78 We set out at Attachment B our analysis of Stage 1's investment need and need date, which draws on submissions and cross-submissions and considers the potential impact of Covid-19 and the recent market activities.

79 Vector submitted that Transpower should verify the assumptions it used to represent the load response sensitivity against observed responses to voltage events. [120]

80 In its cross-submission, Transpower responded that:[121]

80.1 it was not possible to observe the voltage events that result in a widescale loss of voltage-sensitive load because the under and overvoltage conditions required to cause such an event have not existed under recent demand and generation levels in the WUNI region. If it waited to validate its assumptions in the real-world before investing, Transpower considered it would risk the very event it is investing to avoid (cascade failure); and

80.2 Transpower had observed local voltage events that resulted in the loss of voltage-sensitive load at a single or a small number of grid exit points (**GXPs**), or during low load conditions, which support its voltage-sensitive load assumptions.

*Demand forecast and potential impact of Covid-19*

81 MEUG submitted that:[122]

81.1 the demand forecasts for the WUNI region may be overinflated;

[120] Vector, above n 24, at pg. 2.

[121] Transpower, above n 27, at pg. 3.

[122] MEUG, above n 23, at pg. 1

81.2 compared with the position in the draft decision, MEUG was not confident that Covid-19 would have little effect on demand over the next 5 to 10 years; and

81.3 it is unclear how implementation of the new TPM guidelines will affect new demand growth.

82 We acknowledge that demand is difficult to forecast and note that:[123]

82.1 under clause D3 of Schedule D of the Capex IM, we must use the demand and generation forecast developed by MBIE and published as EDGS. In Figure B1, we compared Transpower's demand forecast and MBIE's demand forecast and found that Transpower's demand forecasts were consistent with MBIE's. The results showed that overvoltage issues can arise under all EDGS scenarios if the Rankines are not in service during peak demand; and

82.2 the effects on demand of Covid-19 and the TPM that will emerge from the new TPM guidelines are uncertain and may be even harder to predict.

83 By approving a longer timeframe for the approval expiry date for Stage 1 (31 December 2029), we have given Transpower some delivery flexibility so it can respond appropriately to significant drops in demand.

**Major capex project outputs and NTSs**

*NTSs*

84 Genesis submitted NTSs should be prioritised over large capital expenditure commitments until there is greater certainty concerning changes in demand and supply in the WUNI region.[124] Vector agreed with Genesis on this point.[125]

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[123] We note Transpower's view in the MCP, above n 2, at para 2.2.1, that "forecasting load growth is inherently difficult to do with great accuracy. It is likely to be even harder in the longer term given the potential for electrification and investment in emerging technologies."

[124] Genesis, above n 7, at pg. 2.

[125] Vector, *Cross submission on the draft decision on Stage 1 of Waikato and Upper North Island staged major capex project*, 17 July 2020, at pg. 1.

85 MEUG was not satisfied that Transpower had proactively considered the option of using demand-side management to defer capital expenditure.[126] Vector seconded this view in its cross-submission.[127] MEUG noted Transpower had not advised the outcome of its second NTS RFI and questioned whether Transpower had considered the point raised by Enel X New Zealand Limited (**Enel X**) in its submission on the initial RFI.[128] Enel X had submitted that, "in order to have a reliable and firm capacity of a demand management resource, participants need to be encouraged with fixed availability payments to justify the business case and focus of participating."[129]

86 In its cross-submission, Transpower responded that:[130]

86.1 it did consider NTSs in line with the Capex IM requirements and it also did not receive any responses from demand response vendors. Regarding Enel X's point, Transpower advised that it stated in its RFI that it was open to considering establishment, availability, and delivery payments for NTSs. Transpower therefore did not consider payment structure was a barrier to vendors considering its RFI; and

86.2 it is currently undertaking a formal procurement process for an NTS option and it expects to confirm pricing and a decision on whether to go with the NTS option or the Upper North Island DRD in September 2020. Transpower stated it would apply to us for an amendment to the approved major capex project outputs for Stage 1 if the NTS proves a better solution under the Capex IM than the DRD.[131]

87 We consider Transpower conducted an extensive and detailed process of considering and evaluating NTSs – and we note this process is ongoing. We also acknowledge submitters' recommendation that Transpower prioritise NTSs until there is greater certainty on demand and supply – particularly given recent market activities – *provided* the relevant NTS represents the best major capex project output under the Capex IM.

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126 MEUG, above n 23, at pg. 1.

127 Vector, above n 125, at pg. 1.

128 MEUG, above n 23, at pg. 1. Enel X's submission, *RE: Waikato and Upper North Island Voltage Management consultation*, 22 July 2019, is available at: https://www.transpower.co.nz/sites/default/files/plain-page/attachments/Enel%20X%20-%20Waikato%20and%20Upper%20North%20Island%20Voltage%20Management%20submission_0.pdf.

129 Enel X's submission, above n 128, at pg. 2.

130 Transpower, above n 27, at pg. 2.

131 Above n 27, at pg. 2.

88 Transpower is seeking to establish whether the NTS option noted above is a better solution under the Capex IM. We are assured by Transpower's commitment to seeking an amendment to the approved major capex project outputs if, following our decision, this proves to be the case.[132] We expect Transpower to take the same approach if it reaches a similar conclusion concerning the scope for grid-scale batteries to provide voltage support services as an NTS.

89 As outlined in our draft decision,[133] if Transpower applied for an amendment to one or more approved major capex project outputs for Stage 1, we would assess and determine the application according to the requirements of Part 6 and Division 2, Schedule H of the Capex IM.[134] If we approved Transpower's application, we could also make commensurate amendments to the MCA and exempt major capex.[135]

*Post-fault DMS*

90 Vector expressed concern that the proposed post-fault DMS could cause more interruptions for customers on its network from maloperation. To minimise this risk, Vector submitted that:[136]

90.1 all non-critical GXPs should be armed on a rotation basis regardless of size; and

90.2 as the party best placed to manage risks relating to transmission voltage, Transpower should install any load-shedding equipment at the GXP level.

91 In its cross-submission, Transpower agreed that it was best placed to install any load-shedding equipment at the GXP level, but identified several technical constraints that make it infeasible to adopt Vector's suggestion that all non-critical GXPs should be armed on a rotation basis.[137]

92 We recommend that Transpower and Vector discuss the technical aspects of the post-fault DMS during the implementation stage of Stage 1.

**TPM and the electricity market**

93 Several submitters commented on the TPM and the electricity market.

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132 Above n 27, at pg. 2.

133 Draft decision, above n 5, at paragraphs 72 and 73.

134 Clause 3.3.6(5) of the Capex IM. This would involve evaluating an application to amend an approved major capex output in accordance with the criteria under clause 6.1.1(2) and (5) of the Capex IM and in accordance with the criteria under Division 2, Schedule H of the Capex IM, respectively.

135 Clause 3.3.6(8) of the Capex IM.

136 Vector, above n 24, at pg. 2.

137 Transpower, above n 27, at pg. 3.

94 Vector submitted that ongoing uncertainty as to the allocation of transmission charges made it difficult to comment on the WUNI MCP. Vector requested an estimate of the changes to existing transmission charges for connected parties by applying the new TPM guidelines.[138] Vector felt this was a key consideration for impacted parties when making submissions on Stage 1.[139]

95 In cross-submissions:

95.1 NZ Steel expressed concern at the market structure and regulatory framework underpinning the new TPM guidelines. NZ Steel prefers the current TPM's regional coincident peak demand-based interconnection charge and recommended we step back and relook at the cause and effect of transmission investment, and where the risks and costs will fall, before approving Stage 1 and other projects;[140]

95.2 MEUG endorsed Vector's request for an indication or estimate of the allocation of transmission charges based on the new TPM guidelines (ie, including the benefits-based charge). MEUG suggested several categories of 'beneficiary' on which the estimate could be based. MEUG considered that in a workably competitive market, a supplier would proactively provide customers such information and that the Commission should set such an expectation.[141] We note that the Capex IM requires Transpower to provide with an MCP an estimate of the expected increase in transmission charges due to the proposed expenditure. We consider this requirement applies based on the current TPM, rather than the TPM which will be developed under the new TPM guidelines; and

95.3 Transpower confirmed it has recently begun the process to develop a TPM in line with the new TPM guidelines by 30 June 2021. However, Transpower advised that at this stage it is not possible to estimate the changes to existing transmission charges for connected parties by applying the new TPM guidelines.[142]

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138 Vector, above n 24, at pg. 2.

139 Above n 24, at pg. 1

140 NZ Steel, *Re: Cross submission on draft decision for Stage 1 Waikato and Upper North Island Voltage Management staged capex project proposal (WUNIVM)*, 17 July 2020, at pg. 2.

141 MEUG, *Draft decision on Stage 1 of Waikato and Upper North Island Voltage Management staged major capex project Upper Waitaki Line Project – cross-submission*, 17 July 2020, at pg. 2.

142 Transpower, above n 27, at pgs. 2-3.

96 The TPM in its current or future forms is a matter for the Electricity Authority and is not part of the Capex IM's investment test or criteria for approving a major capex proposal. We understand submitters' desire to get visibility of who the beneficiaries of a proposed investment are likely to be before submitting on the proposed investment. However, we also accept Transpower's cross-submission that it is at an early stage of preparing a TPM under the new TPM guidelines,[143] so Transpower is unlikely to be in position to give such a view.

## Attachments A to E provide the criteria, analysis, and reasons underpinning our decision

97 The criteria applicable to, and the analysis and reasons for, our decision above are set out in Attachments A to E below. Specifically:

97.1 Attachment A sets out our evaluation criteria under the Capex IM which comprise the general criteria, specific criteria, and the investment test;

97.2 Attachment B provides our evaluation of the MCP against the general criteria;

97.3 Attachment C provides our evaluation of the MCP against the specific criteria;

97.4 Attachment D provides our evaluation of Transpower's application of the investment test; and

97.5 Attachment E sets out a summary and our assessment of Transpower's consultation under the Capex IM.

[143] Transpower's TPM development process is underway. Transpower is updating stakeholders on this at: https://www.transpower.co.nz/industry/transmission-pricing-methodology-tpm.

# Attachment A: Evaluation criteria

A1 This attachment sets out the evaluation criteria against which we evaluated the MCP under the Capex IM.

A2 The Capex IM required us to evaluate the MCP against three sets of criteria:

A2.1 the *general criteria* for evaluating all capex proposals in Part 6;

A2.2 the *specific criteria* for MCPs in Schedule C; and

A2.3 the *investment test* in Schedule D, Division 1.

## General criteria for evaluating all capex proposals

A3 The general criteria for evaluating all capex proposals under the Capex IM are:

A3.1 whether what is proposed is consistent with the Capex IM and, where relevant, the Transpower IMs;[144]

A3.2 the extent that what is proposed will promote the purpose of Part 4 of the Act;[145] and

A3.3 whether, the data, analysis, and assumptions underpinning what is proposed are fit for the purpose of the Commission exercising its powers under Part 4 of the Act, including consideration as to the accuracy and reliability of data and the reasonableness of assumptions and other matters of judgement.[146]

## Assessing whether what is proposed is consistent with the input methodologies

A4 The Transpower IMs provide for recoverable costs associated with staging projects[147] and the revenue impact of such projects we have approved.[148] These provisions do not apply here because:

A4.1 the revenue impact of staging projects is not a part of the regulatory approval process for a staging project;[149] and

144 Clause 6.1.1(2)(a) of the Capex IM.

145 Clause 6.1.1(2)(b) of the Capex IM.

146 Clause 6.1.1(2)(c) of the Capex IM.

147 Clause 3.1.3(1)(d) of Transpower IM.

148 Clause 3.7.4(4) of the Transpower IM.

149 Part 3 of the Transpower IM.

A4.2 recoverable costs are associated with Transpower recovering the operating costs of an NTS, and the MCP did not propose an NTS.[150]

A5 The Capex IM sets out the requirements that Transpower must follow when developing and proposing a staging project, and that we must follow when evaluating a major capex proposal for such a project.

A6 When assessing whether the MCP was consistent with the Capex IM, we evaluated the proposal's compliance with:

A6.1 the process requirements;[151]

A6.2 Transpower's consultation requirements;[152]

A6.3 the information requirements;[153] and

A6.4 certification requirements.[154]

**The process requirements**

A7 The Capex IM requires Transpower to notify us of its intention to plan a major capex project or a staged major capex project.[155]

A8 Transpower must agree with us:

A8.1 a consultation programme;

A8.2 approach to considering NTSs;

A8.3 application date; and

A8.4 approval timeframe.[156]

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150 As noted above, if, after our decision, Transpower determines that the NTS under evaluation is a better output under the Capex IM than the DRD approved in this decision, Transpower has stated it will apply to us for an amendment to the approved major capex project outputs for Stage 1 under clause 3.3.6(1)(c) of the Capex IM. If we approved such an amendment, we would then:

- under clause 3.3.6(6) and (8) of the Capex IM, specify the maximum recoverable costs, recovery scheme, and commissioning date for the NTS; and
- under clause 3.3.6(8) of the Capex IM, make commensurate amendments to the major capex allowance and exempt major capex.

151 Clause 3.3.3 of the Capex IM.

152 Clause 8.1.3 of the Capex IM.

153 Schedule G of the Capex IM.

154 Clause 9.2.1 of the Capex IM.

155 Clause 3.3.1(1) and (2) of the Capex IM.

156 Clause 3.3.1(3) of the Capex IM.

A9 Together with Transpower, we must publish the matters agreed in the above paragraph[157] and regularly review and update these matters. We may (after considering Transpower's views) amend any of these matters to ensure they remain appropriate and reasonable.[158]

**Transpower's consultation requirements**

A10 The requirements for Transpower's consultation programme and its approach to considering NTSs are set out in clause 8.1.3 of the Capex IM.

A11 Transpower must consult on the following matters: [159]

A11.1 the investment need;

A11.2 each demand and generation scenario variation;

A11.3 key assumptions;

A11.4 long list of options including any potential NTSs (ie, the long-list consultation); and

A11.5 short list of options including the results of the investment test (ie, the short-list consultation).

**The information requirements**

A12 Transpower must provide the following information:

A12.1 information on the investment need; [160]

A12.2 information on relevant demand and generation scenarios; [161]

A12.3 information relating to each investment option; [162]

A12.4 information relating to proposed investment; [163]

A12.5 major capex project output; [164]

A12.6 information on consultation; [165]

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157 Clause 3.3.1(6) of the Capex IM.

158 Clause 3.3.1(7) of the Capex IM.

159 Clause I1(1) of Schedule I of the Capex IM.

160 Clause G2 of Schedule G of the Capex IM.

161 Clause G3 of Schedule G of the Capex IM.

162 Clause G4 of Schedule G of the Capex IM.

163 Clause G5 of Schedule G of the Capex IM.

164 Clause G6 of Schedule G of the Capex IM.

165 Clause G7 of Schedule G of the Capex IM.

A12.7 information on NTSs;[166] and

A12.8 any additional supporting material Transpower reasonably considers is relevant to our decision on the major capex project.[167]

A13 The Capex IM also requires that:[168]

A13.1 the number of investment options in a major capex proposal is appropriate given the magnitude of the estimated expenditure and the complexity of the investment need associated with the proposed investment; and

A13.2 the specificity of information and the rigour and comprehensiveness of the analysis for each investment option described in a major capex proposal must be commensurate with the estimated expenditure and complexity of that option.

**Certification requirements for MCPs**

A14 Transpower's chief executive officer (**CEO**) must certify in respect of a major capex proposal that:[169]

A14.1 the information provided under Schedule G of the Capex IM was derived from and accurately represents, in all material respects, Transpower's operations;

A14.2 the proposed investment to which the information under Schedule G relates was approved in accordance with the applicable requirements of Transpower's director and management approval policies; and

A14.3 the major capex proposal complies, in all material respects, with the information requirements set out in Schedule G.

A15 Our assessment of Transpower's compliance with the general criteria in respect of the MCP is set out in Attachment B, except for the section on Transpower's compliance with the consultation requirements under Schedule I1 of the Capex IM, which is discussed in Attachment E.

## Specific criteria for evaluating major capex proposals

A16 The specific criteria for evaluating a major capex proposal are set out in Schedule C of the Capex IM, and are outlined as follows:

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[166] Clause G8 of Schedule G of the Capex IM.

[167] Clause G9 of Schedule G of the Capex IM.

[168] Clause 7.4.1(2) and (3) of the Capex IM.

[169] Clause 9.2.1 of the Capex IM.

A16.1 we must evaluate whether the proposed investment satisfies the investment test;[170]

A16.2 we must have regard to at least one of the following factors:

A16.2.1 whether the investment and investment options reflect GEIP, are technically feasible, can be implemented in terms of all application statutory planning and regulatory requirements, and can be integrated in the network and market operations;[171]

A16.2.2 whether the estimated time for construction, commissioning date and completion date are reasonable;[172]

A16.2.3 whether key assumptions around outages planning are reasonable;[173]

A16.2.4 the extent that Transpower has had regard to views of interested parties in consultations;[174] and

A16.2.5 the impact of sensitivity analysis on the electricity market benefit of the proposed investment and investment options;[175] and

A16.3 we must also evaluate Transpower's proposed:

A16.3.1 MCA;[176]

A16.3.2 approval expiry date;[177]

A16.3.3 major capex project outputs;[178] and

A16.3.4 major capex incentive rate.[179]

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170 Clause C1(1) of the Capex IM.

171 Clause C2(a) of the Capex IM.

172 Clause C2(b) of the Capex IM.

173 Clause C2(c) of the Capex IM.

174 Clause C2(d) of the Capex IM.

175 Clause C2(e) of the Capex IM.

176 Clause C3 of the Capex IM.

177 Clause C4 of the Capex IM.

178 Clause C5 of the Capex IM.

179 Clause C6 of the Capex IM.

A17 The Capex IM lists evaluative techniques and approaches we may use in the specific evaluation but enables us to use any other technique or approach we consider appropriate in the circumstances.[180] We can also use any additional information that we consider relevant.[181]

A18 We discuss our assessment of the MCP against the specific criteria in Attachment C and our evaluation of the MCP under the investment test in Attachment D.

## Our discretion when deciding a staging project

A19 After evaluating a major capex proposal, we can decide to either:

A19.1 approve the major capex project or staging project as proposed by Transpower;[182] or

A19.2 decline the major capex project or staging project.[183]

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180 Clause C7 of the Capex IM.

181 Clause 6.1.1(1)(a)(ii) of the Capex IM.

182 Clause 3.3.5(1)(a) of the Capex IM.

183 Clause 3.3.5(1)(b) of the Capex IM.

# Attachment B: Evaluation against general criteria for capex proposals

## Purpose of this attachment

B1 In this attachment, we explain how we evaluated the MCP against the general criteria for evaluating capital expenditure proposals set out in Part 6 of the Capex IM.

## The criteria in Part 6 of the Capex IM

B2 The general evaluation criteria set out in Part 6 are:[184]

B2.1 whether what is proposed is consistent with the Capex IM;

B2.2 the extent to which what is proposed will promote the purpose of Part 4 of the Act; and

B2.3 whether, the data, analysis, and assumptions underpinning what is proposed are fit for the purpose of exercising our powers under Part 4 of the Act.

## Stage 1 is consistent with the Capex IM

B3 To be consistent with the Capex IM, the proposed expenditure must be 'major capex' as defined in the Capex IM,[185] and Transpower must meet the notification, consultation, information, and certification requirements that apply.[186]

B4 We are satisfied that the proposed expenditure is major capex and that Transpower met the Capex IM requirements on notification, consultation, information and certification. The details of our assessment of the individual requirements follow.

### The proposed expenditure for Stage 1 is major capex

B5 The Capex IM defines 'major capex' as expenditure that:[187]

B5.1 is incurred to meet the GRS or provide a net electricity market benefit;

B5.2 is forecast to have an aggregate capital cost exceeding $20 million;[188] and

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184 Clause 6.1.1(2) of the Capex IM.

185 Clause 1.1.5(2) of the Capex IM.

186 Clause 3.3.1, clause 7.4.1, Schedule I, Schedule G, and clause 9.2.1, respectively.

187 Clause 1.1.5(2) of the Capex IM.

188 Under clause 3.3.2(2) of the Capex IM:

a) the forecast capital cost of Stage 1 need not exceed $20 million; but

b) the aggregate forecast cost of all staging projects for the Project must exceed the base capex threshold.

B5.3 is not asset replacement, asset refurbishment, business support, or information system and technology assets.

B6 The proposed expenditure for Stage 1 is consistent with the above definition because it:

B6.1 has a forecast expenditure greater than $20 million;[189]

B6.2 is not an asset replacement, asset refurbishment, business support or information system and technology assets; and

B6.3 is for expenditure that will be incurred to meet the GRS.

*The proposed expenditure for Stage 1 is needed to meet the GRS*

B7 The proposed expenditure for Stage 1 is needed to meet the N-1 criterion of the GRS. This is because the expenditure will ensure that, with all assets reasonably expected to be in service, the power system will remain in a secure state following the tripping of one of the transmission assets in the core grid.

B8 Transpower's system studies conclude that the worst-case N-1 fault in the WUNI region is an outage of Unit 5. A Unit 5 outage reduces the WUNI region's voltage stability limit to 3170 MW.[190] As we outline from paragraph B10 below, a prolonged Unit 5 outage could in certain circumstances result in an 'N-G-1'[191] fault in the WUNI region.

B9 While Unit 5 is a generating unit and not part of the core grid,[192] Unit 5 is connected to the core grid. Transpower considers, and we agree, that for the purpose of applying the N-1 criterion of the GRS, it is sufficient that an unplanned outage occurring on a generating unit connected to the core grid poses a risk to the satisfactory state of the power system.[193] Applying the GRS in a way that captures the effect of an outage or removal from normal service of significant assets connected to the core grid is consistent with both:

B9.1 the integrated nature of the power system; and

189 We note that under clause 3.3.3(2)(b) of the Capex IM, while the aggregate forecast capital expenditure for the Project (comprising all staging projects) must exceed the base capex threshold of $20 million, the forecast expenditure for Stage 1 itself does not need to exceed this threshold.

190 MCP power systems analysis report, above n 95, at Figure 7, pg. 25.

191 As Transpower sets out in the MCP, above n 2, at pg. 4: 'N-G-1' is a grid security standard that ensures that with a generator out of service Transpower's transmission system remains in a satisfactory state following a single fault event (eg, a circuit outage). The 'G' in N-G-1 is also a proxy for a slightly less severe transmission equipment contingency.

192 The assets comprising the core grid are listed in Schedule 12.3 of the Code and include the 220kV Otahuhu-Huntly line. Unit 5 connects to the 220kV Otahuhu-Huntly line at Huntly 220kV bus B.

193 Under clause 1.1(1) of the Code, a 'satisfactory state' means that none of the following occur on the power system: overloading of primary transmission equipment; loss of load; unacceptable voltage conditions; and network instability.

B9.2 the purpose of the GRS which is to provide a basis for Transpower and other parties to appraise opportunities for transmission investments and transmission alternatives.[194]

*Stage 1 will deliver a 'partial' N-G-1 level of grid security*

B10 Transpower may invest over and above the N-1 level of grid security required under the GRS if doing so is economically justifiable—that is, if the relevant investment option has the highest net benefit under clause D1(1)(c) of Schedule D of the Capex IM.

B11 As our analysis and conclusions in Attachments C and D show, we are satisfied Transpower has demonstrated that, as part of Stage 1, it is economically justifiable to invest to maintain a *partial* 'N-G-1' level of security. We explain the basis for and the implications of this as follows.

B12 As noted above, the Transpower's proposed expenditure for Stage 1 is needed to meet the N-1 criterion of the GRS. However, Transpower considers that investment is needed to cover specific, long-duration N-G-1 outages that could occur on the grid (eg, Unit 5 or an outage on the Brownhill-Pakuranga cable (**BHL-PAK**)) in the WUNI region can be out of service for a long time).

B13 We agree with Transpower that, provided it is economically justifiable to do so, it is prudent to invest to guard against these long-duration outages even if the rest of the proposed expenditure only delivers an N-1 level of grid security.[195]

B14 Transpower designed its post-fault DMS for Stage 1 on this basis – to guard against the specific N-G-1 outages described above. Transpower considers that the post-fault DMS will ensure the transmission network remains in a satisfactory state in the event of an outage of, for example, Unit 5, and the loss of another element, such as a generator, circuit, or reactive device.[196] Provided it is technically feasible and economically justifiable, we accept Transpower's view that the post-fault DMS ensures the proposed expenditure for Stage 1 delivers a partial N-G-1 security level, which is needed in the circumstances.

B15 We analyse the technical feasibility of the post-fault DMS at paragraphs C24 to C26, and C31 to C34 of Attachment C below and the economic basis for the post-fault DMS as part of the different investment options evaluated under the investment test in Attachment D.

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194 Clause 2(1) of Schedule 12.2 of the Code.

195 MCP, above n 2, at n 27, pg. 31.

196 MCP power systems analysis report, above n 95, at para 3.2.2.

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

B16 We are satisfied that Transpower's notification of 27 May 2016 complied with clause 3.3.1(1) of the Capex IM.[197] This is because the notification advised us of Transpower's intention to plan the Project.

B17 Transpower's notification of 27 May 2016 also proposed the matters required under clause 3.3.1(2) of the Capex IM. [198] In June 2016, Transpower agreed with us a consultation programme including the long-list and short-list consultations, and an approach for Transpower to seek proposals on NTSs.[199]

B18 Transpower and the Commission have published, regularly reviewed, and updated the matters under clause 3.3.1(2):[200]

B18.1 Our letter agreeing to the matters Transpower proposed is published on Transpower's website where Transpower has also published the relevant long-list and short-list consultation documents and submissions.[201]

B18.2 We have met with Transpower regularly since the notification and discussed progress and timelines along with other matters.

### Transpower satisfied the consultation requirements

B19 The Capex IM requires Transpower to consult with interested parties on the following matters when preparing an MCP: [202]

B19.1 its investment need;

B19.2 each demand and generation scenario variation;

B19.3 key assumptions;

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

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

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197 Transpower's notification under clause 3.3.1(1) is available at: https://www.transpower.co.nz/sites/default/files/projects/resources/wuni%20proposed%20mcp.pdf. The notification requirement that applied when Transpower notified us under this provision is in clause 3.3.1(1) of the Capex IM that applied in May 2016, which is available here: https://comcom.govt.nz/__data/assets/pdf_file/0026/63881/Consolidated-Transpower-Capital-Expenditure-Input-Methodology-Determination-as-at-5-February-2015.pdf.

198 As per the above footnote, the provision that applied when we agreed these matters with Transpower was clause 3.3.1(2) of the Capex IM that applied in May 2016, which is available here: https://comcom.govt.nz/__data/assets/pdf_file/0026/63881/Consolidated-Transpower-Capital-Expenditure-Input-Methodology-Determination-as-at-5-February-2015.pdf.

199 Our letter to Transpower of 1 July 2016 agreeing the matters under clause 3.3.1(2) of the Capex IM is available at: https://www.transpower.co.nz/sites/default/files/projects/resources/Letter%20To%20Transpower%20Dated%201%20July%202016_.pdf.

200 Clauses 3.3.1(6) and (7) of the Capex IM.

201 See: https://www.transpower.co.nz/waikato-and-upper-north-island-voltage-management-investigation-timeline.

202 Clause I1 of Schedule I of the Capex IM.

B20 Transpower's long-list consultation must:

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

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

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

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

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

B21 Transpower's short-list consultation must:[203]

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

B21.2 provide information on the relevant key assumptions;

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

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

B22 Transpower carried out its long-list consultation in July 2016 and its short-list consultation in June 2019 and November 2019 in a manner consistent with the above requirements. We summarise our evaluation of Transpower's consultations in Attachment E.

**Transpower satisfied the information requirements under the Capex IM**

B23 The Capex IM sets out the information that Transpower needs to provide in an MCP.[204] The MCP and the attachments to it that Transpower provided for this purpose are listed in Table B1 below.[205]

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203 Clause I3 of Schedule I of the Capex IM.

204 Schedule G of the Capex IM.

205 These documents are available on our website at: https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-transmission/transpower-capital-investment-proposals/transpower-major-capital-proposal/waikato-and-upper-north-island-voltage-management?target=documents&root=63690; and on Transpower's website at: https://www.transpower.co.nz/waikato-and-upper-north-island-voltage-management-investigation.

B24 Transpower provided a table mapping the information required under the Capex IM with the information provided in its MCP and the attachments.[206]

B25 We have reviewed the MCP and the attachments against the information requirements set out in clauses G1 to G8 of Schedule G of the Capex IM and are satisfied that Transpower has met the information requirements.

**Table B1: The MCP and attachments**

| Document title |
|---|
| Waikato and Upper North Island Voltage Management major capex proposal (the MCP) |
| Attachment A: Compliance Requirements – 13 December 2019 |
| Attachment B: Power System Analysis Report – 13 December 2019 |
| Attachment C: Options and Costing Report – 13 December 2019 |
| Attachment D: Stakeholder consultation summery – 12 December 2019 |
| Attachment E: CEO certification – 13 December 2019 |
| Attachment F: Spreadsheet on pricing by GXP and GIP – 13 December 2019 |
| WUNIVM Report Final GHD advice on modelling |
| WUNIVM cost-benefit analysis for Commerce Commission |

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

B26 Clause 9.2.1 of the Capex IM requires that, before Transpower submits a major capex proposal to us, Transpower's CEO must certify the major capex proposal according to requirements in that provision.

B27 Transpower provided a certificate signed by its CEO in respect of the MCP.[207]

B28 We reviewed this certificate against clause 9.2.1 of the Capex IM and we are satisfied that it meets the relevant requirements.

[206] MCP, above n 2, *Attachment A: Compliance Requirements*, available at: https://comcom.govt.nz/__data/assets/pdf_file/0030/196950/Transpower-WUNIVM-major-capex-proposal-Attachment-A-Compliance-requirement-13-December-2019.pdf.

[207] MCP, above n 2, *Attachment E: CEO certification*, available at: https://comcom.govt.nz/__data/assets/pdf_file/0035/196946/Transpower-WUNIVM-major-capex-proposal-Attachment-E-CEO-certification-13-December-2019.pdf.

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

B29 Under the general evaluation criteria, we must consider "the extent to which what is proposed will promote the purpose of Part 4 of the Act."[208] Alongside the investment test under Schedule D, we consider that this is an important test for an expenditure proposal under the Capex IM.

### The purpose of Part 4 of the Act

B30 The purpose of Part 4 of the Act is to promote the long-term benefit of consumers in markets where there is little or no competition and little or no likelihood of a substantial increase in competition.[209] 'Competition' means 'workable or effective competition'.[210]

B31 To promote workable or effective competition that is to the long-term benefit of consumers, we must promote outcomes in regulated markets that are consistent with outcomes in workably competitive markets. Section 52A(1) of the Act specifies the following four outcomes produced in such markets that we must promote so that regulated suppliers, including Transpower, respectively:

B31.1 have incentives to innovate and invest;

B31.2 have incentives to improve efficiency and provide services at a quality that reflects consumer demands;

B31.3 share the benefits of efficiency gains with consumers, including through lower prices; and

B31.4 are limited in their ability to extract excessive profits.

### The Capex IM and the purpose of Part 4

B32 The Capex IM was enacted under section 54S of the Act as part of the umbrella of requirements set by Part 4 of the Act. The Capex IM has been designed,[211] reviewed,[212] and refined,[213] to promote the purpose of Part 4 under section 52A of the Act.

B33 Clause 6.1.1(2)(b) of the Capex IM restates the overarching test noted above by requiring us to evaluate the extent to which what an MCP proposes will promote the purpose of Part 4.

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208 Clause 6.1.1(2)(b) of the Capex IM.

209 Section 52A(1) of the Act.

210 Section 3(1) of the Act.

211 2012 Capex IM reasons paper, above n 4, at para 1.3.7.

212 2017/18 Capex IM review reasons paper, above n 68, at para X13.1.

213 Commerce Commission, *Transpower Capital Expenditure Input Methodology Amendments Determination 2018* [2018] NZCC 8, available at: https://comcom.govt.nz/__data/assets/pdf_file/0033/88278/2018-NZCC-8-Transpower-capital-expenditure-input-methodology-amendments-determination-2018-25-May-2018.PDF.

**Delivering Stage 1 according to the MCP will promote the outcome under section 52A(1)(b) of the Act**

B34 Under section 52A(1)(b) of the Act, we consider that Transpower delivering Stage 1 according to what is proposed in the MCP will promote the purpose of Part 4 by providing Transpower incentives to improve its efficiency and provide services at a quality that reflects consumer demands.

B35 Our reasons for this view are set out below.

*Delivering Stage 1 will materially reduce the number and frequency of unnecessary and involuntary supply interruptions*

B36 Consistent with section 52A(1)(b) of the Act, delivering Stage 1 will enable and encourage Transpower to provide services at a quality that reflects consumer demands. We consider consumers in the WUNI region expect a level of service from Transpower that involves minimising the number and duration of unnecessary and involuntary interruptions to, or restrictions on, their electricity supply.[214] This is supported by our analysis of Transpower's application of the investment test in Attachment D of this paper, which indicates the size of the electricity market benefits from avoiding the costs of unserved energy relating to the voltage stability issues in the WUNI region.

B37 As outlined in this attachment and in Attachment C, we agree with Transpower's analysis of the MCP's investment need – maintaining voltage stability – and we consider grid investment is necessary to meet this need. Specifically, increasing the transmission network's capacity in the WUNI region will enable Transpower to continue to meet the level of service noted above as demand grows and also if the Rankines are removed from normal service.

*The MCP will promote section 52A(1)(b) of the Act if it provides for Transpower to deliver the right investment at the right time*

B38 Based on our evaluation set out in Attachments B to D of this paper, we consider that the MCP proposes delivery of the right investment at the right time. For the reasons outlined in this section, we consider that in doing so, this will promote section 52A(1)(b) of the Act.

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214 For example, in its submission on the short-list consultation, Vector expressed concern that Transpower's preferred options for a post-fault DMS would result in a higher number of interruptions for Auckland customers – see Vector, *Submission to Transpower's Waikato and Upper North Island Voltage Management Short List consultation*, at para 11, available at: https://www.transpower.co.nz/sites/default/files/plain-page/attachments/Vector%20-%20Waikato%20and%20Upper%20North%20Island%20Voltage%20Management%20submission_0.pdf.

B39 In its submission on our draft decision, Vector agreed with our analysis that whether the MCP promoted the purpose of Part 4 of the Act depended on the timing of its delivery, but noted that more effort should be done to assess the timing.[215] Similarly, Meridian endorsed our analysis of the MCP and submitted that our draft decision to approve Stage 1 would promote the purpose of Part 4 of the Act.[216]

B40 Major capex projects provide assets that have long lifetimes, typically 30 to 50 years or longer in the case of transmission investments, such as transmission lines.[217] Selecting the proposed investment for a major capex proposal requires Transpower to undertake a robust analytical and consultative process under the Capex IM to determine the right type and number of major capex project outputs. The type and number of major capex project outputs Transpower proposes to meet the investment need therefore materially affects:

B40.1 the size of the MCA that Transpower seeks; and

B40.2 the outcome of the investment test under Schedule D of the Capex IM.

B41 The timing of an investment also determines the scale of the electricity market benefit and cost elements it delivers to consumers.[218] If an investment is made before its optimal time, consumers will pay for assets that are not needed to provide the level of service consumers demand at that time. Alternatively, if an investment is deferred then the level of service provided could be affected. In most cases the timing of an investment is based on assumptions that are volatile and often subject to factors outside the control of a supplier such as Transpower. For this reason, before it submits a major capex proposal to us, Transpower must consult widely under the Capex IM on the most appropriate time for a proposed investment.

B42 The analysis above illustrates that a major capex proposal that proposes to deliver the right investment at the right time will incentivise and enable Transpower to improve its efficiency and provide services at a quality that reflects consumer demands, promoting section 52A(1)(b) of the Act. Alongside our evaluation under Attachments B to D, the following paragraphs provide our analysis of whether the MCP provides for Transpower to deliver the right investment at the right time.

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215 Vector, above n 24, at pg. 2. In line with Vector's submission, we consider that our analysis of the demand forecast and need date at Attachment B, which draws on submissions and cross-submissions and considers the potential impact of Covid-19 and recent market activities, is a broad assessment of the timing.

216 Meridian, above n 110, at pg. 2.

217 A proposed investment may also include an NTS, though compared to a transmission investment, an NTS arrangement is more likely to be of a shorter duration.

218 Under clause D4(1) of Schedule D of the Capex IM, 'electricity market benefits and cost elements' are any of the benefits or costs listed in that provision and received by consumers during the calculation period under the relevant demand and generation scenarios.

*We are satisfied that Transpower has proposed the right transmission investment*

B43 In selecting the MCP's proposed investment, Transpower considered and consulted on a wide range of transmission options and NTSs.[219] These included market and non-market generation in the region, energy storage, transmission network reconfiguration, building new transmission lines, upgrading existing transmission lines, and providing dynamic reactive power.

B44 Transpower then prepared a short list of six technically feasible options using the following criteria:[220]

B44.1 fit for purpose;

B44.2 technical feasibility;

B44.3 GEIP;

B44.4 system security as additional benefit resulting from an economic investment; and

B44.5 high-level estimate of capital cost.

B45 We are satisfied with the criteria Transpower used to select a short list of investment options.

B46 Transpower's studies showed that the most technically feasible and cost-effective solution is to provide dynamic reactive power in the WUNI region. Transpower then short-listed six options for providing dynamic reactive power to be tested under the investment test. We are satisfied that the six shorted-listed options are a reasonable number of investment options for further analysis and testing under the investment test.[221]

B47 The investment test under Schedule D of the Capex IM is an economic assessment that uses a range of future scenarios of the electricity market to identify the investment option with the highest expected net electricity market benefit. The test is designed to identify the most dynamically efficient investment option. This option then becomes the preferred investment put forward to us in an MCP.

B48 We consider the investment test enables the selection of the right investment based on the available information and corresponding assumptions about the future composition of the power system. Based on our evaluation in Attachments C and D, we are satisfied with Transpower's application of the investment test and Transpower's choice of the proposed investment as the right investment for the MCP.

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219 Attachment E provides a summary of the submissions on the long-list consultation.

220 Long-list consultation document, above n 49, at Appendix B.

221 Clause 7.4.1(2) of the Capex IM.

*We are satisfied that winter 2023 is the appropriate need date – the right time – for the MCP's proposed investment*

B49 Transpower's analysis of forecast peak demand and voltage stability criteria shows that the proposed investment is needed by winter 2023. This need date is set by the forecast 'prudent' peak demand in the WUNI region and the likely timeframe for the Rankines' potential removal from normal service.

B50 The Rankines' removal from normal service would reduce the voltage stability limits of the transmission network supplying the WUNI region to less than the forecast peak demand in the region. An investment is therefore necessary to increase the system's voltage stability limit and to supply the forecast peak demand.[222]

B51 In assessing the need date for Stage 1, we reviewed:

B51.1 the likely timeframes in which Genesis might remove the Rankines from normal service; and

B51.2 the peak demand forecast for the WUNI region.

B52 We have also considered the potential impact on the need date for Stage 1 of other market activities that occurred after we issued our draft decision.

<u>Delivering Stage 1 by the need date addresses a material risk</u>

B53 In its long-list and short-list consultation documents and the MCP, Transpower assumed Genesis would remove the Rankines from normal service by the end of 2022.[223] In our draft decision, we considered that uncertainty on the Rankines' future is a significant risk in terms of when Transpower should deliver Stage 1. This is because:

B53.1 delivery would require at least 30 months. To deliver Stage 1 by winter 2023, Transpower would therefore need to commence the construction phase later this year; and

B53.2 if the Rankines are removed from normal service before Stage 1 is delivered, this could increase the risk of overvoltage events under N-G-1 system conditions. This is because the overvoltage stability will reduce to the level of the 2018 and 2019 peak demand demands in the WUNI region, as seen in Figure B1 below.

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[222] The voltage stability limit sets the maximum amount of electricity that can be conveyed by the network. If a higher amount is conveyed and a major component of the network fails, the system can become unstable and result in a widespread interruption to supply. We discuss this in Attachment C.

[223] MCP, above n 2, at pgs. 11 and 12. This date was based on Genesis's announcement in April 2016 that it had entered into four-year bilateral commercial arrangements with other market participants that would keep two Rankines available to the end of 2022. Genesis did not disagree with that timeframe but suggested that Transpower do a sensitivity analysis on it (see Long-list consultation document, above n 49, at pg. 13).

B54 As noted above, Genesis provided no further information on the Rankines' future in its submission on our draft decision, saying that ongoing management of the Huntly assets will continue based on market conditions and expected market developments. Genesis will inform the market of any commitments that materially affect Huntly generation capacity in accordance with market disclosure requirements in the Code. Genesis further cautioned against participants making large capex commitments based on an expectation of reduced Huntly generation capacity.[224]

B55 Transpower has sought to manage to the extent possible the uncertainty risk relating to the Rankines' future and the 30-month investment delivery timeframe, but this uncertainty means there is limited scope for Transpower to delay starting the construction phase for Stage 1. However, Transpower further confirmed in its cross-submission that it remains open to deferring one or more Stage 1 major capex project outputs if, by 1 October 2020, it establishes that there:[225]

B55.1 will be no change to Huntly generation until after winter 2023;

B55.2 is a material reduction in peak demand expectation due to Covid-19; or

B55.3 is another material market announcement affecting the investment need of Stage 1.

<u>Transpower's peak demand forecast is reasonable</u>

B56 To assess whether Transpower's peak demand forecast is reasonable, we compared it with EDGS' information on peak demand.[226]

B57 Table B2 below shows the peak demand forecasts in EDGS.[227] EDGS only forecasts peak demand for the year 2050 at the national and North Island level for five scenarios. In providing this forecast, EDGS used the 2017 peak demand as 6,300 MW for New Zealand and 4,250 MW for the North Island. It does not provide a discrete forecast for the WUNI region.

**Table B2: EDGS peak demand in 2050 (MW)**

| Scenario | New Zealand | North Island |
|---|---|---|
| Reference | 8,462 | 5,726 |
| Growth | 9,831 | 6,649 |
| Global | 7,062 | 4,806 |
| Environmental | 9,640 | 6,474 |
| Disruptive | 10,205 | 6,949 |

224 Genesis, above n 7, at pg. 1.

225 Transpower, above n 27, at pg. 2.

226 EDGS, above n 96.

227 Above n 96.

B58 This means that the EDGS peak demand forecast is not sufficiently granular for Transpower to use when assessing the need date of transmission projects. For most transmission projects, Transpower requires forecasts at the regional level.

B59 For this reason, Transpower produced its own peak demand forecast for the WUNI region and consulted on this with stakeholders.[228] In the MCP, Transpower stated that it incorporated the EDGS peak demand forecasts for 2019 into its analysis and updated its peak demand forecast models to reflect the 2018 actual peak demand. Transpower stated that this brought forward the need date for Stage 1 to 2023-2024.[229]

B60 Transpower produces two forecasts known as the ‘prudent’ and ‘expected’ forecasts:

B60.1 the prudent peak demand forecasts mean that there is a 90% probability that actual demand will remain within forecast; and

B60.2 the expected forecast indicates that there is a 50% chance that actual demand will exceed forecast.

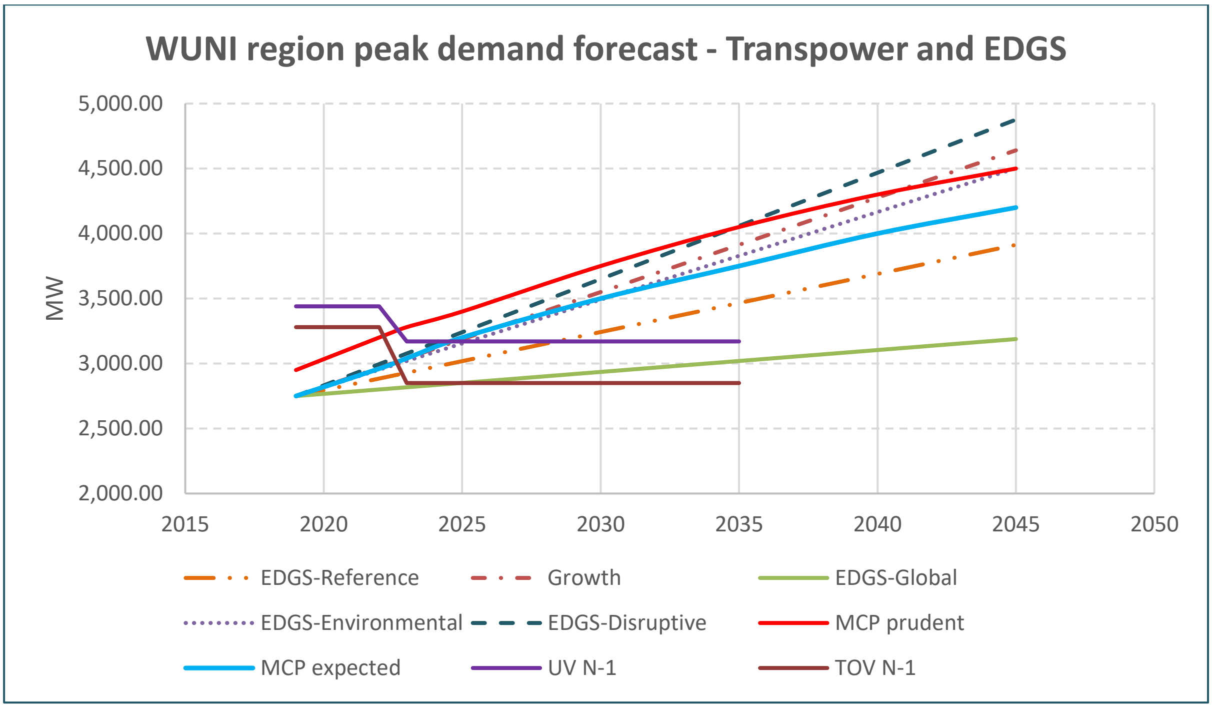
B61 Transpower plans transmission investments against the prudent peak demand forecast. We assessed Transpower’s prudent peak demand forecast here by applying the rate of growth for the North Island peak demand derived from the EDGS forecast and using the WUNI actual peak demand of winter 2018. We assumed a constant rate of growth in peak demand from 2018 to 2050.

B62 Figure B1 below shows Transpower’s expected and prudent peak demand forecasts, our forecast for the five EDGS scenarios, and the undervoltage (UV N-1) and transient overvoltage (TOV N-1) stability limits with and without the Rankines. We provide more information on and analysis of the undervoltage and overvoltage stability limits in Attachment C.

228 We analyse Transpower’s consultation in Attachment E.

229 MCP, above n 2, at pg. 6.

**Figure B1: WUNI region peak demand forecast and voltage stability limits**




B63 Transpower's expected forecast sits in between the five EDGS forecast scenarios. We therefore consider that Transpower's forecast peak demand is consistent with the rate of peak demand growth forecasted in EDGS.

B64 Even for the forecast under the EDGS 'Global' scenario (the lowest peak demand growth out of all five EDGS scenarios), Figure B1 shows that voltage management issues will arise in the WUNI region once the Rankines are removed from normal service.

B65 We discuss below the potential impact of Covid-19 and the recent market activities on forecast peak demand and the implications of this for Stage 1's investment need and need date.

Potential impact of Covid-19 on Stage 1 investment need and need date

B66 We considered whether Covid-19 will affect the investment need or need date of Stage 1. Commentators have forecast that Covid-19 is likely to have an economic impact similar to the GFC.[230] The Treasury has described Covid-19 is a 'once in a century' public health shock that is also having a profound impact on economic and financial systems around the world and in New Zealand.[231]

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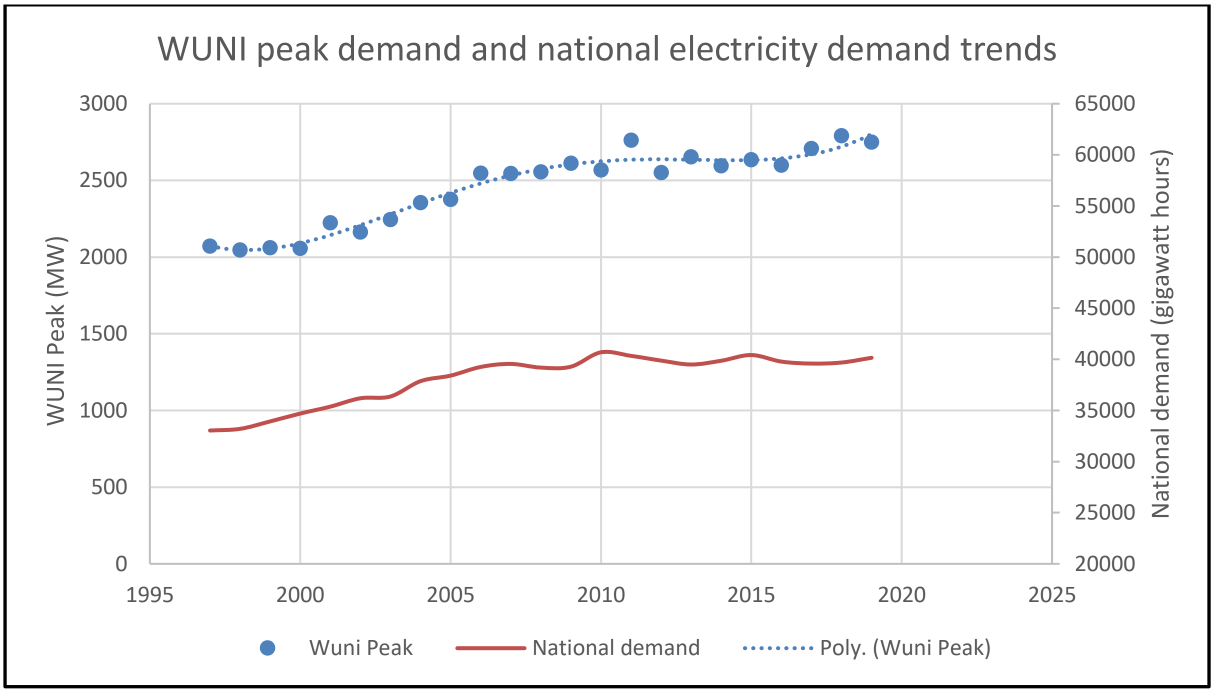
230 For example, the Treasury estimates that the economic impact of Covid-19 will be more severe than the GFC: https://treasury.govt.nz/system/files/2020-04/mei-mar20.pdf, at pg. 8.

231 The Treasury, *Treasury Report T2020/973: Economic scenarios*, 13 April 2020, at Executive Summary, available at: https://treasury.govt.nz/publications/tr/treasury-report-t2020-973-economic-scenarios-13-april-2020-html.

B67 We reviewed what happened to energy demand and peak demand as a result of the GFC. Figure B2 below shows historical peak demand for the WUNI region and the national electricity demand. Since the GFC, both WUNI peak demand and national energy demand flattened and have remained relatively flat.

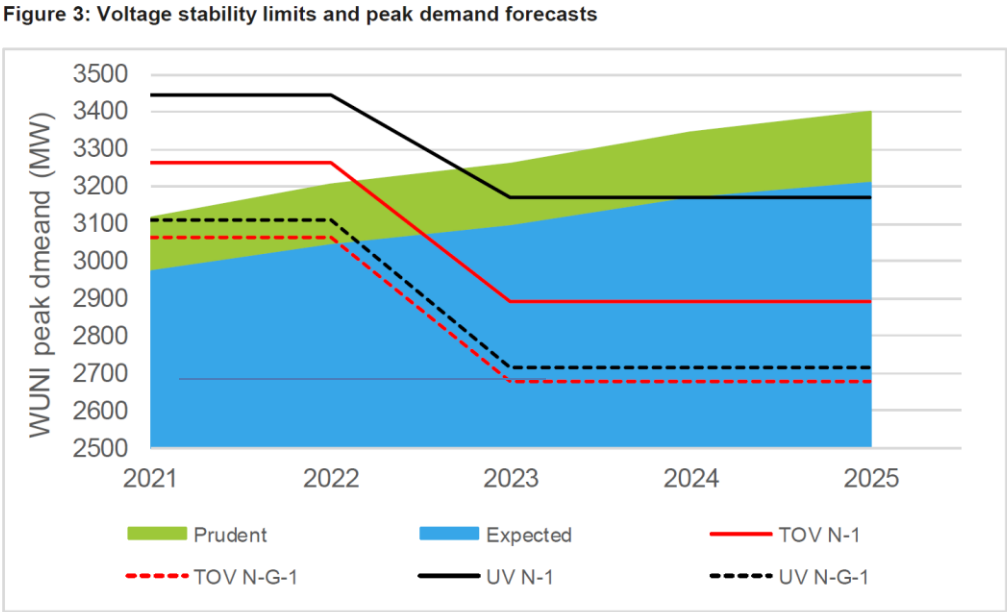
**Figure B2: Electricity peak and energy demand**




B68 Figure B3 below demonstrates the relationship between WUNI peak demand and voltage stability limits. The solid and dashed red lines show the N-1 and N-G-1 undervoltage limits while the solid and dashed black lines the N-1 and N-G-1 overvoltage limits. The voltage stability limits reduce in 2022/2023 when the Rankines are forecast to be removed from normal service. Without the Rankines, the N-G-1 limits are about 2700 MW. These limits are the same as the 2018 and 2019 peak demand of approximately 2750 MW, as shown in Figure B2.

B69 The voltage stability limits and peak demand forecasts show that even if forecast peak demand in the WUNI region flattens or reduces following Covid-19, provided it remains at approximately 2750 MW, without the Rankines, the peak demand will exceed the N-G-1 undervoltage stability limit. This suggests that, on balance, the uncertainties associated with the impact of Covid-19 are unlikely to have a material impact on the investment need or need date of Stage 1.

**Figure B3: Transpower voltage stability limits and peak demand forecasts**




<u>The potential impact of recent market activities on Stage 1 investment need and need date</u>

B70 Since issuing our draft decision, several market activities have occurred that entail potentially substantial changes to the makeup and operation of the power system and wholesale electricity market:

B70.1 the most significant of these activities is Rio Tinto's announcing on 9 July 2020 that it will close the Smelter in August 2021. This would result in a substantial reduction in demand in the lower South Island and a corresponding increase in the amount of lower-cost hydrogeneration available from Manapouri;

B70.2 on 30 June, Transpower announced after consulting with interested parties that it will deliver two further CUWLP upgrades associated with the transmission lines connecting Roxburgh and Livingston substations and Cromwell and Twizel substations. Completing CUWLP will remove a constraint on transporting Manapouri generation and other Southern hydrogeneration to the HVDC at Benmore, allowing for the dispatch of up to an additional 400MW (approximately) from this hydrogeneration.[232] Transpower has since confirmed that it will be able to fast-track completing CUWLP from May 2023 to May 2022;[233] and

[232] See above n 39. Transpower advises that completing CUWLP will increase the capacity of the relevant circuits from 600 MW to 1000 MW, at N-1 conditions – see Transpower, *Clutha Upper Waitaki Lines Project FAQ*, available at: https://www.transpower.co.nz/clutha-upper-waitaki-lines-project-faqs.

[233] See above n 39. Information on Transpower's CUWLP 2020 consultation, submissions, and cross-submissions can be viewed at: https://www.transpower.co.nz/clutha-upper-waitaki-lines-project-consultation-2020.

B70.3 on 10 July, Meridian announced it is considering installing a 100-MW battery system in the North Island to provide instantaneous reserves for when the Smelter closes next year.[234] Contact subsequently advised it too is considering investing in a 50 to 100-MW battery system in the North Island for the same purpose.[235] As noted above at paragraph X29.3, the most recent update from the two generator-retailers is that the battery system could be a joint initiative with a capacity of 100MW and potentially scope to provide voltage support services to Transpower;[236] and

B70.4 two further large, grid-connected industrial load customers in the WUNI region, NZ Steel and Refining NZ, comprising two percent of New Zealand's electricity demand, are undergoing strategic reviews. An outcome from these reviews could be a reduction or cessation in production and electricity demand from these two customers.[237]

B71 Based on our analysis below, we agree with particular submissions that the effect of the above market activities[238] and others – particularly as transmission constraints are alleviated[239] – is to increase the likelihood of the Rankines' removal from normal service. This will occur as lower-cost generation from Manapouri and other Southern hydro power stations displaces the Rankines' higher-cost thermal generation from normal service in the wholesale market offer stack.

B72 Figure B4 below compares the generation from Huntly and the Smelter demand, and Figure B5 below shows the Rankines' daily output for June 2020.

234 See above n 40.

235 See above n 41.

236 Steve Rotherham, above n 28. As noted above at paragraph X22, Transpower has advised that any procurement of battery services as an NTS would be conducted via an open and transparent procurement process.

237 See above n 43.

238 Meridian, above n 110, at pg. 2 and Transpower, above n 27, at pg. 2.

239 Along with the CUWLP transmission constraint, Transpower identifies and discusses other grid constraints at sections 6.3, 6.4 and 6.9 to 6.10 of its *Transmission Planning Report* of December 2019 (available at: https://www.transpower.co.nz/sites/default/files/publications/resources/Transmission%20Planning%20Report%202019.pdf) that may need to be addressed to transport more Southern hydrogeneration north.

**Figure B4: Huntly generation and Smelter demand**

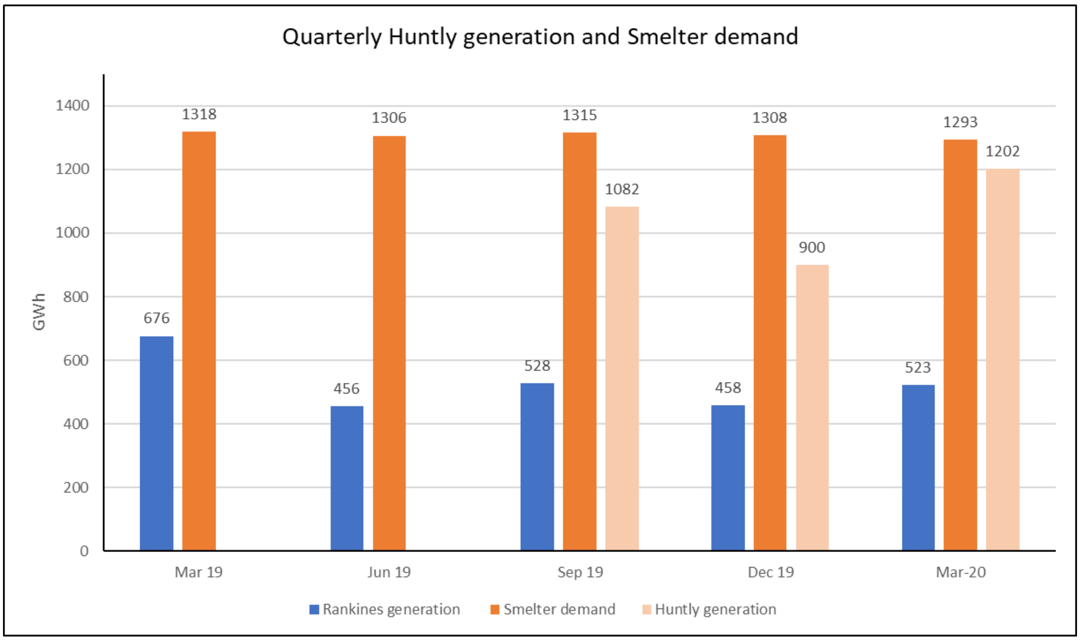
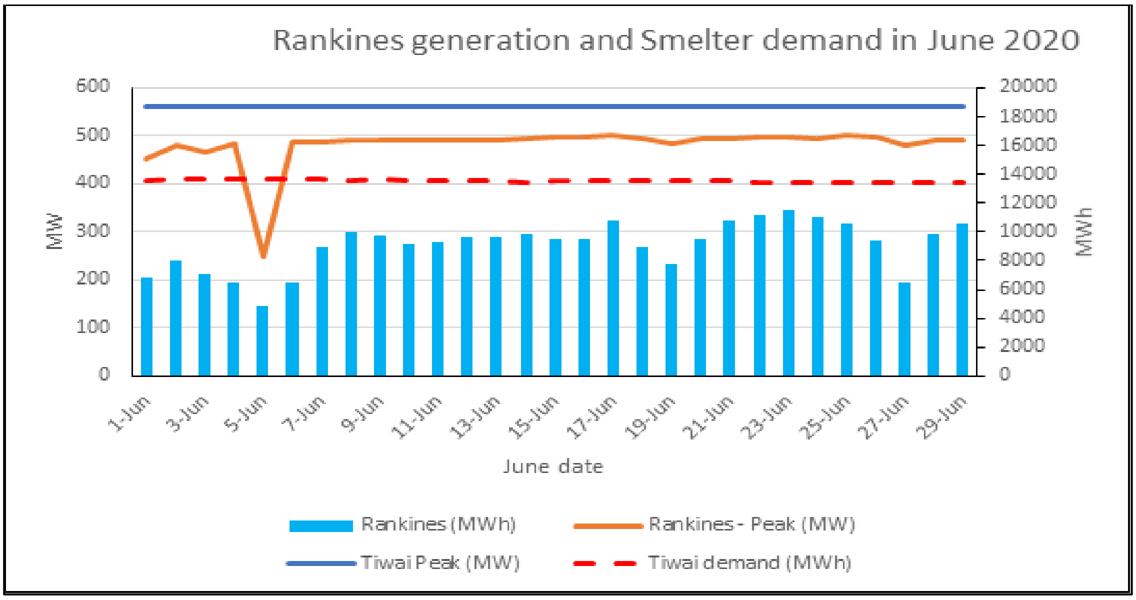



**Figure B5: Huntly daily generation June 2020**




B73 Together, Figure B4 and Figure B5 show:

B73.1 since April 2019 to March 2020, the Smelter's load has been more than twice the Rankines' output;

B73.2 in June 2020, which was considered a dry winter month for hydrogeneration, the Rankines' daily energy output was below the Smelter's daily energy demand of about 13,560 MWh; and

B73.3 in June 2020, the Rankines' daily peak output of 500 MW was below the Smelter's daily peak demand of 560 MW.

B74 On this basis, we consider that after the Smelter closes and approximately 500 MW (700 GWh per quarter) of additional hydrogeneration can be transported to the North Island, it is likely that the Rankines will not be required for normal service.

B75 We do not consider there is enough information to conclude that these recent market activities will advance the need date for Stage 1. This is primarily because the detailed supply and demand dynamics of these activities, and their implications for the power system and wholesale market, remain uncertain. This makes it difficult to conclude with certainty at this point that Stage 1's need date will be brought forward.

B76 For the reasons outlined in this section, we are satisfied that the MCP's proposed need date was reasonable, but needs to be monitored in the light of market activities, and that the MCP proposed the right investment at the right time, promoting section 52A(1)(b) of the Act and the purpose of Part 4.

## The data, analysis, assumptions and analytics underpinning the MCP are fit for the purpose of us exercising our powers under Part 4 of the Act

B77 Under clause 6.1.1(2)(c) of the Capex IM, we are satisfied that the data, analysis, and assumptions underpinning the MCP are fit for the purpose of us exercising our powers under Part 4 of the Act. As we evaluated the MCP, Transpower provided the additional information listed below in Table B3.

**Table B3: Additional information provided by Transpower**

| Document title |
|---|
| Details on the cost estimates including conceptual design report |
| WUNI peak demand forecasts |
| Information on post-fault DMS, including its design features and integration with the market systems and system operations |
| Details on the calculation of the MCA |

# Attachment C: Evaluation against specific criteria

## Purpose of this attachment

C1 This attachment explains how we have evaluated the MCP against the specific criteria set out in Schedule C of the Capex IM, as required under clause 6.1.1(4) of the Capex IM.

C2 There are three parts to our evaluation under Schedule C:

C2.1 evaluating the MCP against specific criteria in clause C1(1) and (3);

C2.2 having regard to the general factors under clause C2, and the specific factors relating to individual MCP components, in evaluating the MCP; and

C2.3 employing an evaluation technique under clause C7 in evaluating the MCP.

## The specific criteria for evaluating an MCP

C3 Our specific criteria for evaluating an MCP under Schedule C of the Capex IM can be broken down as follows:

C3.1 *investment test*: clause C1(1) requires us to evaluate whether the MCP's proposed investment satisfies the investment test in Schedule D of the Capex IM. Under clause C1(2), if the MCP relates to a staged major capex project, as is the case here, then the investment test must be satisfied for each staging project;[240] and

C3.2 *specific components*: clause C1(3) requires us to evaluate, to the extent applicable to the proposed investment, specific components of the proposed investment.

C4 Under clause C1(3) of Schedule C, the specific components of a proposed investment that we must evaluate depend on whether it includes an NTS.[241] The MCP's proposed investment does not include an NTS, so under clause C1(3), we have evaluated the MCA, major capex project outputs, approval expiry date, major capex incentive rate, exempt major capex, and the commissioning date assumption.

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240 We discuss the results of the investment test in Attachment D.

241 Clause C1(3) of Schedule C of the Capex IM exhaustively sets out the components that we must evaluate to the extent applicable to the transmission investment or NTS.

## Factors to have regard to and evaluation techniques we may employ in evaluating an MCP

C5 In evaluating the specific criteria noted above, Schedule C specifies factors we must have regard to and techniques we may use:

C5.1 *General factors to have regard to*: clause C2 requires us to have regard to at least one of the general factors listed in clause C2(a) to (e) when evaluating an MCP;

C5.2 *Factors to have regard to in evaluating specific components*: clauses C3 to C6 each specify a list of factors from which we must choose at least one factor from each list to have regard to in evaluating the specified components of Stage 1. The relevant components under these provisions are, respectively, the MCA and maximum recoverable costs; the proposed approval expiry date; the proposed major capex project outputs; and the proposed major capex incentive rate; and

C5.3 *Evaluation techniques*: clause C7 sets out evaluation techniques we may employ in undertaking the evaluations described above.

**The evaluation techniques we used in evaluating the MCP under Schedule C**

C6 Under clause C7 of Schedule C, in evaluating the MCP, we may employ one or more of the following evaluation techniques:

C6.1 powerflow analysis and dynamics in the grid (clause C7(a));

C6.2 detailed critiques of conceptual designs to estimate cost and time estimates (clause C7(b));

C6.3 analysis and review of costs and benefits associated with the MCP's proposed investment and investment options (clause C7(c));

C6.4 critiques of market development scenarios used in the MCP (clause C7(d));

C6.5 unit rate benchmarking (clause C7(e)); and

C6.6 any other technique or approach we consider appropriate in the circumstances (clause C7(f)).

*Our evaluation of Transpower's powerflow analysis and dynamics in the grid*

C7 In support of the MCP, Transpower's power systems analysis report identifies the modelled need for the MCP's proposed investment and the need date. This report contains:[242]

C7.1 details of dynamic analysis modelling assumptions including demand forecast and generation scenarios used, dynamic load modelling as it affects voltage recovery following faults, and justifications for dynamic faults used to define investment need dates and proposed reactive support capacity;

C7.2 the dynamic analysis criteria used such as the network voltage recovery envelope, which is used to ensure network voltages remain within acceptable limits and avoid network voltage collapse due to sustained network undervoltage, and avoid equipment damage due to network over voltages;

C7.3 discussion of the investment need, driven by undervoltage and overvoltage analysis and the effects of removing the Rankines from normal service;

C7.4 the results of a dynamic power system analysis study and selected voltage recovery waveforms, demonstrating when and where dynamic reactive support needs to be installed in the transmission network;

C7.5 the short-list options studied including short-list options with different grid security standards (such as N-1 and N-G-1) and an NTS; and

C7.6 details of one of the MCP's major capex project outputs – a post-fault DMS for tripping selected feeder lines in the WUNI region in the event of selected N-1 network outages in the region.[243]

C8 We reviewed the MCP power systems analysis report and consider that its analysis of the dynamic undervoltage stability and overvoltage issues in the WUNI region is in-depth and robust.

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[242] MCP power systems analysis report, above n 95.

[243] Above n 92, at Appendix 6.

C9 In line with clause C7(a) of Schedule C of the Capex IM, we have used the MCP power systems analysis report in evaluating the proposed investment, investment options, and modelled projects.[244] Based on its assumptions, we agree with the report's conclusions regarding the investment need and need date for Stage 1, and also Transpower's analysis of the short-list options it considered, for the following reasons:

C9.1 Transpower has analysed and modelled dynamic undervoltage issues in the WUNI region since 2005 when it first proposed solutions to network capacity issues in the region. Transpower has considerable experience in analysing dynamic voltage stability issues – particularly as they relate to this region – and we consider the analysis done for the MCP is sound;

C9.2 while Transpower's P90 demand forecast estimate used in the analysis is arguably conservative, there is considerable uncertainty surrounding the effect of load on undervoltage and network instability, and post-fault network overvoltage; and

C9.3 the analysis assumptions used, including fault types, fault durations and the voltage recovery envelope, which all affect the need date, are all reasonable.

C10 As outlined immediately below, in assessing whether the MCP's proposed investment satisfies the investment test, we also employed the evaluation technique under clause C7(c) of Schedule C.

**Clause C1(1) – whether the MCP's proposed investment satisfies the investment test**

C11 Our evaluation of Transpower's application of the investment test is outlined in Attachment D. We employed the technique under clause C7(c) of Schedule C to assist our evaluation: an analysis and review of Transpower's calculation of the costs and benefits associated with the proposed investment and investment options in the MCP.

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

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

C12.2 that the proposed investment has the highest expected net electricity market benefit, and this is positive; and

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244 Clause D8(4) of Schedule D of the Capex IM defines 'modelled project' as assets, other than those that are part of an investment option-
(a) which are likely to exist-
(i) as part of a demand and generation scenario; and
(ii) during the calculation period for any investment option based on that scenario; and
(b) for which the likelihood, nature and timing of their existence are affected by an investment option proceeding.

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

**Clause C1(3) – evaluation of specific components of the MCP**

C13 The MCP does not include an NTS. The MCP's proposed investment is a transmission investment. Accordingly, the relevant MCP components we must evaluate are:[245]

C13.1 MCA (clause C3);

C13.2 approval expiry date and commissioning date assumptions (clause C4);

C13.3 major capex project outputs (clause C5); and

C13.4 major capex incentive rate (clause C6).

C14 Our evaluation of these MCP components and how we tested the MCP against the requirements of Schedule C is outlined in the following sections.

**Clause C2 – general evaluation of the MCP**

C15 Under clause C2 of Schedule C, we must have regard to at least one of the factors listed in clause C2(a) to (e) when evaluating a major capex proposal.

C16 Our analysis below sets out how we have had regard to each of these factors in evaluating the MCP.

*Clause C2(a)(i) – does the proposed investment and investment options reflect GEIP?*

C17 In evaluating the MCP, we have had regard to whether Transpower's proposed investment and investment options reflect GEIP. We consider that GEIP reflects the appropriate planning and performance standards of a prudent supplier.[246]

C18 Transpower's transmission planning and performance standards are appropriate and have underpinned Transpower's analysis of, and investment to mitigate, dynamic voltage issues in the WUNI region since 2005. Transpower also sought external international expertise to test the appropriateness of those planning and performance standards, particularly when analysing overvoltage effects.[247]

C19 We consider that Transpower has been prudent in selecting and consulting on investment options that account for the considerable uncertainty surrounding the Rankines' future and the effect this has on the investment need and need date. Transpower has proposed an appropriate investment strategy given the lead time from identifying the need to the installation of the major capex project outputs proposed for Stage 1.

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245 Clause C1(3) of Schedule C of the Capex IM.

246 Commerce Commission, *Transpower's individual price-quality path from 1 April 2020 – Decisions and reasons paper* (**RCP3 IPP decisions paper**), 29 August 2019, at para 2.8, available at https://comcom.govt.nz/__data/assets/pdf_file/0028/170398/Transpower-IPP-for-RCP3-Decisions-and-reasons-paper-29-August-2019.PDF.

247 MCP, above n 2, at pgs. 22 and 23.

C20 In our view, Transpower's proposed investment and the investment options it selected and consulted on reflect GEIP.

*Clause C2(a)(ii) – is the proposed investment and investment options technically feasible?*

C21 The proposed investment and investment options Transpower considered in its short-list consultation are all well-tested technologies in New Zealand and internationally. These technologies are installed to manage dynamic under and overvoltage issues such as those identified by Transpower in the MCP.

C22 The proposed investment includes two DRDs, each with a +/- 150 Mvar dynamic range. Transpower proposes locating one device in Otahuhu, Auckland and the other in Hamilton. In the MCP, Transpower proposes that the DRDs could be static var compensators (**SVCs**) or STATCOMs,[248] both of which are mature transmission technologies installed in many locations around the world.

C23 In our draft decision, we gave our view that DRDs – whether they are SVCs or STATCOMs – are a technically feasible proposed investment under clause C2(a)(ii) of Schedule C of the Capex IM. Transpower has since confirmed that the DRDs it intends to procure following our decision will be STATCOMs, whose installed cost will be cheaper than the SVC option available. We endorse this approach given that the STATCOMs will deliver the same level of technical performance as the more expensive SVCs.

C24 The MCP also proposed a post-fault DMS for use in the event of selected long-duration outages in the WUNI region – for example, following a fault on the BHL-PAK cable, since cable faults can take a long time to repair.

C25 We sought additional information from Transpower about how it proposes to operate the post-fault DMS, including steps Transpower proposes to take to prevent maloperation of the DMS; whether the DMS is consistent with the applicable requirements of the Code; and how the DMS may affect system and market operations. Transpower responded to our questions stating that:

C25.1 To minimise the risk of maloperation, Transpower would put in place a range of measures for the DMS, such as:

C25.1.1 the DMS will be infrequently armed – only when the risk of voltage collapse in the WUNI region is high;

C25.1.2 there will be safeguards against maloperation for local voltage disturbances, relay faults, and human error;

C25.1.3 Transpower will use modern relays that allow specialised voltage rate-of-change functionality to be programmed rather than using standard rate-of-change-of-voltage relays;

[248] Both SVCs and STATCOMS are in operation in the New Zealand power system.

C25.1.4 the DMS will operate based on actual voltage conditions rather than for pre-defined faults; and

C25.1.5 the DMS will include the usual risk mitigation measures applied to Transpower's special protection schemes (**SPSs**).

C25.2 Transpower also confirmed that the DMS is consistent with:[249]

C25.2.1 the system operator's principal performance obligations under clauses 7.2A to 7.2D of the Code (**PPOs**); and

C25.2.2 Transpower's asset owner obligations under Part 8 of the Code.[250]

C25.3 The DMS will be similar to many other demand-shedding SPSs installed in the transmission network, and Transpower is confident that the DMS will be successfully integrated into existing system and market operations.[251]

C26 We are satisfied Transpower has demonstrated that the DRDs are technically feasible. We also consider that Transpower has taken all reasonable steps to mitigate potential issues with the post-fault DMS and that it is technically feasible.

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

C27 Transpower intends to install the relevant major capex project outputs at its own sites so it already has full property and access rights. We sought further information from Transpower about the RMA processes and regulatory consents the Stage 1 major capex project outputs would require.

C28 Transpower advised that:[252]

C28.1 it has designated the Otahuhu and Hamilton substations in the Auckland Unitary Plan and the Hamilton City Plan, respectively, and installing the DRDs would be within the scope of these designations;

C28.2 the two sites are already well-established substations there is little risk of any issues arising in the planning process;

249 Under sections 5 and 8(1) of the Electricity Industry Act 2010, Transpower is the system operator – the person who ensures the real-time coordination of the power system.

250 Email from Nic Deller (WUNI Project Manager – Transpower) to Hazet Adam (Commerce Commission) on 17 April 2020.

251 Email from Nic Deller (WUNI Project Manager – Transpower) to Hazet Adam (Commerce Commission) on 24 April 2020.

252 Email from Nic Deller (WUNI Project Manager – Transpower) to Hazet Adam (Commerce Commission) on 27 March 2020.

C28.3 it is likely that a resource consent will be required from Hamilton City Council and Auckland City Council under the RMA for soil disturbance at the two sites;

C28.4 depending on the design of the DRDs, regional consents may also be required from the Auckland Regional Council or Waikato Regional Council, for example, for stormwater discharge; and

C28.5 any consents required under the RMA and/or regional consents would likely be obtained on a non-notified basis and are not expected to be a significant risk in terms of delaying the delivery of Stage 1.

C29 We accept Transpower's assessment that there are unlikely to be any material planning impediments to delivering Stage 1 by the need date.

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

C30 Transpower has a proven track record of installing and operating DRDs as evidenced by the three SVCs already in operation in the New Zealand power system. We are satisfied that Transpower will be able to integrate these major capex project outputs into the existing system and market operations.

C31 As noted above, Transpower provided further details on the proposed post-fault DMS, stating that it would only operate in extreme situations (selected N-1 outages) and only for the purpose of ensuring the power system remained in a satisfactory state and within voltage stability limits.

C32 This post-fault DMS will not be a voluntary one, though Transpower intends to agree in advance with affected parties the WUNI region feeder lines that Transpower will trip if the DMS is triggered. While Transpower still has design issues to resolve regarding the speed of operation and size and location of load blocks to be tripped under the DMS, Transpower is confident the DMS will integrate into the existing system and market operations.

C33 As noted above, we tested Transpower on whether the post-fault DMS was consistent with existing system and market arrangements and rules under the Code. The system operator confirmed that the DMS was consistent with the PPOs and the asset owners' obligations under Part 8 of the Code.[253]

C34 We therefore consider that the proposed investment and investment options can be integrated into the existing system and market operations.

[253] Email from Nic Deller (WUNI Project Manager – Transpower) to Hazet Adam (Commerce Commission) on 17 April 2020.

*Clause C2(b) – is the estimated time required for construction, consultation, meeting statutory planning and other regulatory requirements, and obtaining property and access rights prior to a proposed commissioning date or completion date reasonable?*

C35 In the MCP, Transpower describes the need date for Stage 1 as follows:[254]

> Given current information that [the Rankines] may retire by the end of 2022, the need date for investment to manage voltage issues is ahead of winter 2023. This project timeline, allowing for regulatory approval, procurement, detailed design, build and commissioning, is tight.

C36 Transpower states that the need date is driven by load growth and the decision surrounding the Rankines' future. If Genesis decommissions the Rankines, the need date will be driven by dynamic undervoltage issues. A failure to mitigate such undervoltage issues could result in widespread dynamic voltage collapse. Transpower further states that:[255]

> Even if the [Rankines] are not decommissioned, and rather retained or replaced, we expect that load growth in the region will result in the risk of N-1 voltage stability limits being exceeded from as early as winter 2024 under a prudent forecast, rising with continued demand growth.

C37 If the Rankines remain in normal service, Transpower will have an additional year beyond the current need date to deliver Stage 1. Either way, Transpower is confident that it can deliver Stage 1 by winter 2023, stating that:[256]

> As with any project, and consistent with the incentive regime, we intend to deliver this project as efficiently as possible. We assume Stage 1 components (excluding Stage 2 preparatory works) are commissioned at the end of 2022, based on our current forecast of the delivery phase of the project.

C38 While the delivery timeframe is challenging, Transpower is confident it can deliver Stage 1 by the end of December 2022. The winter 2023 peak loads, which drive the need date for Stage 1, will also not begin to manifest until between April and June 2023. There is therefore some contingency (early 2023) built into Transpower's project delivery planning.

C39 For these reasons, we consider that Transpower's planning and delivery timeframe to meet the need date is reasonable.

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

C40 We sought information from Transpower about the outage planning required for the construction and commissioning of the DRDs.

C41 Transpower advised that:

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254 MCP, above n 2, at pg. 7.

255 Above n 2, at pg. 7.

256 Above n 2, at pg. 45.

> Outages will be required for connection to [the] existing 110kV [bus at the Hamilton substation] and [the] 220kV [bus at the Otahuhu substation] during the bus extension/connection phases of the project. Both buses have redundancy to allow for bus extension and connection, so there are no concerns for these outages at this stage.

C42 Transpower provided further detail for the outage processes at both substation sites:

> [Otahuhu]: the [DRD] will be connected to bus N and M which currently has two capacitors (C30 and C31) both of which can be connected to either bus as required. During the connection of the bus extension, one of bus N or M will be out of service at any one time while the other remains in-service. We conservatively estimate each bus being out of service for 1 week during connection. The outage will be planned during a time where there is sufficient capacitive redundancy elsewhere in the network. Furthermore, we expect to be able to return the other bus to service in 4-8 hours in the event of a forced recall of the bus.
>
> [Hamilton]: the [DRD] will be connected to the 110 kV bus. During connection, we will remove BOB-HAM-2 from service for up to a week. This will reduce security of supply to Bombay, but we do not expect load to be on N security as there is generally sufficient redundancy of supply from the BOB-HAM-1 and BOB-OTA-WIR 1 and 2 circuits, depending on system conditions. This outage may require load or generation agreements to maintain N-1 security at BOB, which will be secured before proceeding with the outage in accordance with our usual outage planning processes.

C43 We consider that Transpower's outage planning assumptions, as outlined above, are reasonable.

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

C44 Clause 3.3.1(9) of the Capex IM requires Transpower to consult interested persons in accordance with its consultation programme and to follow its published approach for considering NTSs.[257] Under clause 8.1.3(1)(a) of the Capex IM, Transpower's consultation programme must provide for Transpower to consult prior to submitting an MCP on such matters specified in Schedule I of the Capex IM, as applicable.[258]

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

[258] In Attachment E, we provide more information on our review of Transpower's consultation against the requirements of Schedule I of the Capex IM.

C45 Transpower's stakeholder consultation summary documents Transpower's long-form and short-form consultations, feedback on those consultations, and Transpower's response to that feedback.[259] The stakeholder consultation summary demonstrates that:

C45.1 Transpower identified and consulted interested parties on a range of potentially viable NTSs, amongst other technical matters;[260]

C45.2 most interested parties that submitted on the consultations agreed with Transpower's approach to NTSs;[261] and

C45.3 Transpower responded to interested parties that queried or sought further information from it on NTSs.[262]

C46 Under clause C2(d) of Schedule C, we consider that Transpower had regard to interested parties' views on NTSs in their submissions on the long-list and short-list consultations.

C47 As mentioned above on 2 October 2019, Transpower issued an RFI on NTSs. Transpower completed the RFI on 26 November 2019 and received three responses. In submitting the MCP to us on 13 December 2019, Transpower advised it had not completed its evaluation of the three responses but would update us on the outcomes of its evaluation and amend the MCP, if necessary, in March 2020.[263]

C48 Specifically, Transpower advised that:[264]

> If we determine one or more of these responses are viable, we will update our short-list options, re-apply the Investment Test, and update our proposal. We may stage NTS components separately from transmission components in order to determine firm prices through a formal procurement process before seeking approval of an MCA for NTS.

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259 MCP, above n 2, *Attachment D: Stakeholder Consultation Summary* (**MCP stakeholder consultation summary**), available at: https://comcom.govt.nz/__data/assets/pdf_file/0033/196953/Transpower-WUNIVM-major-capex-proposal-Attachment-D-Stakeholder-consultation-summary-13-December-2019.pdf.

260 Above, n 2, at paras 2.2 to 2.4.

261 Above n 2, at para 4.4.

262 Above n 2, at para 4.4.

263 Transpower, *MCP cover letter*, 13 December 2019, at pg. 2, available at: https://comcom.govt.nz/__data/assets/pdf_file/0037/196948/Transpower-Letter-to-Commerce-CommissionWUNIVM-major-capex-proposal-13-December-2019.pdf.

264 MCP, above n 2, at para 4.1.1.

C49 Transpower has since confirmed in its cross-submission on our draft decision that it is in a procurement process concerning an NTS option arising from the NTS RFI. If, after our decision, Transpower finds that the NTS under evaluation is a better output under the Capex IM than the DRD approved in this decision, Transpower has stated it will apply to us for an amendment to the approved major capex project outputs for Stage 1 under clause 3.3.6(1)(c) of the Capex IM.[265] If we approved such an amendment, we would then:

C49.1 under clause 3.3.6(6) and (8) of the Capex IM, specify the maximum recoverable costs, recovery scheme, and commissioning date for the NTS; and

C49.2 under clause 3.3.6(8) of the Capex IM, make commensurate amendments to the major capex allowance and exempt major capex.

C50 We would expect Transpower to take the same approach of applying for an amendment to the Stage 1 approved major capex project outputs if it reaches a similar conclusion in respect of the scope for a battery system to meet the Stage 1 investment need.

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

C51 This is discussed in our evaluation in Attachment D of Transpower's application of the investment test to the proposed investment for Stage 1.

**Clause C3 – evaluation of the MCA**

C52 We have set an MCA of $143.0 million,[266] in 2022/23 prices.[267] The MCA requested includes the estimated cost of delivering Stage 1, an allowance for uncertainties in scope, price changes, forecasted exchange rates and inflation from 2019 to 2023 and financing costs.

C53 Table C1 summarises the components of the MCA.

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265 Transpower, above n 27, at pg. 3.

266 This number is different from:

- the MCA in the MCP ($144.5 million), reflecting changes made as Transpower has updated its cost estimate; and
- the MCA we approved in our draft decision ($154.1), reflecting the lower cost of the STATCOMs that Transpower has decided to procure as DRDs.

267 This MCP does not include any recoverable costs as these relate to NTSs.

**Table C1: Summary of the components of the MCA**

| MCA component | Amount ($million) |
|---|---|
| Base estimate | 104 |
| Uncertainties | 27 |
| P50 estimate of cost (real) | 131 |
| CPI | 5 |
| IDC | 7 |
| MCA | 143 |

*The MCA appears reasonable but is subject to a high level of uncertainty*

C54 We consider that the 'base estimate' component of the MCA is reasonable based on the underlying calculations and assumptions before us and given the amount of expenditure proposed for Stage 1.

C55 Given we consider that the base estimate is reasonable, our view is that the MCA is reasonable.

C56 In reaching this view on the MCA, we are mindful of the high level and number of sources of uncertainty in scope and inherent at this early phase of the Project.[268] In our analysis and decision on the exempt major capex in paragraphs C107 to C110 below, we discuss how we have decided to manage the potential adverse impact of this uncertainty.

*Our approach to evaluating the MCA*

C57 Under clause C3 of Schedule C, we must consider at least one of the following factors when evaluating the MCA:

C57.1 how Transpower used the major capex project outputs, key drivers, key assumptions, and cost modelling to determine the P50 and MCA;[269]

C57.2 the capital costing methodology and formulation, including unit rate sources, the method used to test the efficiency of unit rates and the level of contingencies included;

C57.3 the impact of forecast costs on other costs of Transpower, including the relationship with operating expenditure;

C57.4 mechanisms for controlling actual capital expenditure with respect to the MCA; and

268 We discuss the uncertainty and potential impact of Covid-19 and recent market activities on the Stage 1 investment need and need date at Attachment B.

269 Under clause 1.1.5(2) of the Capex IM, 'P50' means estimated aggregate project costs where the probability of the actual aggregate project costs being lower than that estimated is 50%.

C57.5 the efficiency of the proposed approach to procurement of goods and services.

C58 In evaluating Transpower's proposed MCA, we considered the factors under clause C3(a) and (b):

C58.1 how Transpower used the major capex project outputs, key drivers, key assumptions, and cost modelling to determine the P50 and proposed MCA; and

C58.2 the capital costing methodology, including unit rate sources, the method used to test the efficiency of unit rates and the level of contingencies included in the estimate.

C59 To assess the capital cost of the MCP's proposed investment, Transpower provided us with:

C59.1 conceptual design reports that set out the conceptual scope of works; and

C59.2 costing spreadsheet that included unit costs, estimated quantities, and associated uncertainties.

C60 We assessed the estimated capital costs by:

C60.1 reviewing the above documents; and

C60.2 seeking further clarification and explanation from Transpower.

C61 We met several times with Transpower when assessing the cost estimates. The objective of these meetings was to establish whether the scope, unit costs and estimated quantities in the above documents were reasonable.

C62 In March 2020, Transpower obtained a revised price for the supply and installation of the two DRDs. Following our discussions and the revision to the DRDs' price, Transpower refined the scope of the works and provided us with a revised estimate of the capital costs.

C63 We summarise our evaluation of the components of the MCA in the sequence listed in Table C1 above.

*Clause C3(a) – how Transpower used the MCP's major capex project outputs, key drivers, key assumptions, and cost modelling to determine the P50 and MCA*

C64 The P50 estimate consists of a base estimate for the major capex projects outputs and an allowance for contingencies. Together with the P50 estimate, the MCA also includes financing costs and forecasts for inflation. Table C1 above shows how the components combine to form the MCA.

C65 Transpower developed base estimates of the major capex projects outputs and summed them to provide a combined base estimate for Stage 1. This estimate includes the costs of site works, costs to procure, install and commission all assets as well as overhead costs.

C66 Since Transpower has still to determine the site for the post-fault DMS and the Stage 2 investments, the estimate has some additional assumptions built into it on site and quantities. These assumptions form part of the contingencies discussed below.

C67 Transpower catered for the following uncertainties as contingencies in the MCP's P50 estimate:

C67.1 equipment uncertainty: this existed because Transpower has only recently finalised the type and manufacture of the DRDs, and the type and manufacture affect the quantity of the associated site works. As noted above at paragraph 54, Transpower has removed this uncertainty by opting for the STATCOMS as the preferred DRDs;

C67.2 estimating uncertainty to allow for scope, price and timing risks: allowing for this uncertainty recognises that not all works can be identified at this early phase, contractor prices can vary, and delivery can be delayed due to externals events such as weather; and

C67.3 Covid-19 uncertainty: this uncertainty provides for an additional allowance relating to Covid-19's potential impact on the timing and price of delivering Stage 1.

C68 Transpower estimated the P50 value of the above uncertainties using a triangular probability distribution. We are satisfied that the value of the uncertainties is reasonable and consistent with clause G5(2)(c) of Schedule G of the Capex IM, which requires the proposed MCA to be a P50 of the capital cost and the estimated probability distribution of the P50.

C69 In our decision at paragraph C107 below on exempt major capex, we discuss how we have treated these uncertainties so that neither Transpower nor the consumer is disadvantaged in respect of expenditure that is outside Transpower's reasonable control.

C70 We are satisfied with Transpower's approach to deriving the cost estimates for each major capex project output, the key assumptions it has made, and the modelling of uncertainties done to determine the P50 and the MCA. These ensure we can clearly link the MCA to each major capex project output, which is particularly useful if Transpower later applies to amend or adjust a major capex project output in the future.

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

C71 We evaluated the base estimate using the technique of the capital costing methodology and formulation under clause C3(b) of Schedule C.

C72 We assessed how Transpower prepared the base estimate and whether the underlying assumptions appear reasonable.

C73 The capital costing methodology reflects how Transpower proposes to deliver Stage 1. Transpower proposes to deliver:

C73.1 the DRDs through a design, manufacture, supply and build contract with a single manufacturer of such devices. The successful contractor will install and commission the DRDs on sites owned and prepared by Transpower; and

C73.2 the balance of the works through local contractors. This includes preparing the sites for the DRDs and installing all the network equipment required to connect them to the network.

C74 Based on the delivery model described above, Transpower used the following methods to form the base estimate:

C74.1 including in the estimate the prices from manufacturers to design, manufacture, supply, and build the DRDs;

C74.2 using a bottom-up assessment to cost the engineering components of the balance of works; and

C74.3 using modelling based on the scope, project cost, and timeframe for delivering Stage 1 to estimate the costs of overheads, project management and engineering support.

C75 The bottom-up assessment has three components – the itemised work packages, quantities for the work packages, and unit prices:

C75.1 Transpower develops the itemised work packages from conceptual design drawings based on site investigations, knowledge and experience from similar previous projects and existing site drawings to identify the scope of works;

C75.2 Transpower derived three sets of quantities for each of the itemised work packages.[270] Each set of quantities reflect the three different types of DRD that Transpower could procure.[271] Transpower set the lowest of the three costs as the base cost and included the additional costs as equipment uncertainties; and

C75.3 Transpower uses its Enterprise Estimation System (**TEES**) as the source for unit costs for the itemised packages. The quantities and unit costs provided the base estimate for the respective itemised work packages.

C76 We assessed Transpower's itemised work packages and are satisfied that these reflect the work packages necessary to deliver projects of this nature.

[270] An example of the quantity for site excavation is the area and depth of excavation required at a site.

[271] There are different makes and types of DRD. The capital cost of each make and type varies, and these variations are reflected in three sets of cost estimate. Transpower will select the DRD with the lowest life-time cost.

C77 The quantities are based on conceptual information and assumptions on ground conditions, potential routes for cables and the characteristics of the equipment that will be installed. In our evaluation, we sought to establish whether these quantities appeared reasonable. We had several discussions with Transpower on its estimated quantities. Transpower subsequently amended these quantities as it refined the assumptions used to forecast them.

C78 TEES includes a database of Assembly costs which is the source of the unit costs Transpower used in its costing methodology. The Capex IM requires us to evaluate the unit rates[272] and the method used to test the efficiency of unit rates,[273] as follows:

C78.1 an Assembly is a package of work with one or more cost items underneath it. Transpower considers that Assemblies can provide the level of more granular and site-specific costs required to estimate the cost of the Project;

C78.2 as part of the recent IPP reset, we evaluated TEES and assessed how Transpower keeps the unit costs in TEES current.[274] The same process is used to keep current the unit cost in Assemblies. We were satisfied that Transpower had a sound process for keeping the unit costs current. For example, Transpower updates external labour and material rates based on the actual costs incurred in completing a project; and

C78.3 while Transpower updates unit costs to reflect the most current information and the unit costs are market based, we consider that the unit costs do not necessarily reflect efficient market costs because of the small size of the market participants. As part of the IPP reset, we set reporting requirements on Transpower that will allow us to assess the efficiency of Transpower forecasts and the unit costs;[275] and

C78.4 in analysing the MCA’s unit costs, we asked Transpower to provide us with randomly selected Assembly costs. We tested whether Transpower correctly used these costs in its cost estimation for the MCA. Based on our sample testing, we are satisfied that:

C78.4.1 the current unit costs are reflected in Transpower’s cost estimation; and

C78.4.2 the Assemblies are sufficiently granular for the purpose of estimating the cost of Stage 1.

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272 Clause C7(e) of Schedule C of the Capex IM refers to unit rate benchmarking. Here we have considered how Transpower keeps its unit rates current.

273 Clause C3(b) of Schedule C of the Capex IM.

274 RCP3 IPP decisions paper, above n 246, at Attachment H.

275 Above n 242, at paras H28 to H36. The reporting requirements we set for Transpower are set in our section 53ZD notice relating to cost estimation, available at: https://comcom.govt.nz/__data/assets/pdf_file/0037/188785/Transpower-s53ZD-notice-Cost-estimation-24-February-2020.pdf.

*Analysis under clause C3(b) of the level of contingencies included in the base estimate*

C79 The level of contingencies Transpower included in the MCP's base estimate is $38.9 million (in 2022/23 prices) or 25.2% of the MCA. As noted above at paragraph 54, Transpower's decision to procure the STATCOMs as DRDs has removed equipment uncertainty, lowering the level of contingencies to $27.3 million (in 2022/23 prices) or 19% of the MCA.

C80 As mentioned at paragraph C67 above, Transpower has accounted for contingencies relating to uncertainty in estimating for scope, price and timing risks, and Covid-19 uncertainty.

C81 We consider these risks have a reasonable possibility of materialising and have therefore included them in the MCA. This allows Transpower to recover these costs should they materialise.

C82 We are mindful that the MCA's contingency allowance can produce windfall gains for Transpower under the incentive mechanism if the relevant risks do not materialise. To manage this possibility, we have made the contingency allowance exempt major capex under clause 3.3.5(7)(c) of the Capex IM. This means that Transpower's capital expenditure relating to these uncertainties will not be subject to the major capex incentive rate and Transpower will not make windfall gains if the risks do not arise. We discuss this further in our decision at paragraph C107 below on exempt major capex.

*Exchange rate and inflation*

C83 The exchange rate and general inflation elements of the MCA are washed-up, which means these assumptions do not impact on the calculation of incentives or the final amount of revenue Transpower can recover.[276]

C84 Transpower's underlying assumptions relating exchange rate and general inflation elements, shown below in Tables C2 and C3, have been identified so that an accurate wash-up can occur.

**Table C2: Exchange rate used to calculate the MCA**

| Currency | Exchange rate |
|---|---|
| NZ | 1 |
| SEK | 5.7424 |
| THAI Baht | 18.5907 |
| USD | 0.572 |
| AUD | 0.9591 |
| EUR | 0.526 |

[276] Clause B3(1) of Schedule B of the Capex IM.

| | |
|---|---|
| JPY | 72.232 |

**Table C3: Forecast inflation rate used to calculate the MCA**

| Year | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 |
|---|---|---|---|---|---|---|---|---|
| Rate | 1.74% | 1.50% | 1.67% | 1.60% | 1.90% | 2.10% | 2.00% | 2.00% |

*Financing costs*

C85 Transpower has calculated its financing costs using:

C85.1 the assumption that expenditure occurs at the end of each month; and

C85.2 the same principles used in Transpower's base capex proposal.[277]

C86 The capital expenditure profile of Stage 1 is the 'S' curve typical of such projects. Most expenditure will occur towards the commissioning phase of the DRDs' construction due their high costs. These costs are fixed under contract at an early point.

C87 Site preparation works that are done in the early stages of the construction phase are where variations in scope or delays, and corresponding increased costs, are most likely. Due to the comparatively lower costs of the site preparation works for Stage 1, the effect of variations to capital expenditure profile on the financing costs is not high.

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

C88 Transpower proposes an approval expiry date of 31 December 2029.[278]

C89 The effect of an approval expiry date is that Transpower cannot recover the costs of any assets commissioned after this date. This incentivises Transpower to deliver Stage 1 within the approval expiry date or apply for an amendment to that date under clause 3.3.6(1)(d) of the Capex IM.

C90 In evaluating Transpower's proposed approval expiry date under clause C4 of Schedule C, we must have regard to at least one of the six factors listed in that provision.

C91 We tested Transpower's proposed approval expiry date against the factor set out at clause C4(a): the effect of the proposed approval expiry date on the quantified and unquantified costs and benefits under the investment test.

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

278 Under clause 1.1.5(2) of the Capex IM, an 'approval expiry date' is the date on which the approval we give in respect of a major capex project under clause 3.3.5 of the Capex IM expires.

C92 In selecting its proposed approval expiry date, Transpower stated that:[279]

> We have proposed an approval expiry date of 31 December 2029, which is six years after the commissioning date assumption of 31 December 2022. We have proposed this extra period because a major generation announcement post-approval but before we have committed to expenditure could defer the need for the grid outputs for Stage 1 for several years. If this happens it will be efficient to have a reasonable window during which we will not have to re-apply for investment approval.

C93 We consider that deferring the proposed investment will affect the ranking of the short-list options Transpower consulted on. It is not clear from the materials Transpower provided us that it explicitly tested the effect of deferral, although a likely upper bound proxy for a deferral scenario is the '2030 Rankine retirement' scenario in Transpower's sensitivity analysis.[280]

C94 If it eventuated, the 2030 Rankine retirement scenario would change the ranking of preferred options, making deferral the most economically attractive.[281] This is because the removal of the Rankines from normal service is the main driver for the MCP's proposed investment.

C95 Even if the Rankines remain in service beyond 2023, Transpower's analysis in Figure B2 above show additional reactive power support will still be required to manage dynamic overvoltage effects.

C96 Given our analysis above, the result of Transpower's sensitivity analysis, and the uncertainty surrounding the Rankines' future, we consider that Transpower's proposed approval expiry date for Stage 1 (31 December 2029) is a reasonable one.

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

C97 In evaluating Transpower's proposed major capex project outputs under clause C5 of Schedule C, we must have regard to at least one of the four relevant factors listed in that provision.

C98 We tested Transpower's proposed major capex project outputs against the factor set out at clause C5(a): the extent to which the major capex project outputs reflect the nature, quantum and functional capability of the transmission investment assets to be commissioned.

C99 Transpower summarises the major capex project outputs proposed for Stage 1, as follows:[282]

C99.1 procure, install and commission two DRDs, each capable of delivering (within 10%) 150 MVAr capacitive to 150 MVAr inductive at nominal voltage: one in the Upper North Island and the other in the Waikato;

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279 MCP, above n 2, at pg. 44.

280 Above n 2, at pgs. 35 to 36.

281 Above n 2, at pg. 35.

282 Above n 2, at pg. 13.

C99.2 design, install and commission a post-fault DMS for the WUNI region; and

C99.3 conduct preparatory works for Stage 2, including additional investigation, consultation, obtaining property rights and environmental approvals, design work and non-binding tendering for future series capacitors and installation works on the BHL-WKM lines.

C100 We are satisfied that the major capex project outputs Transpower proposes for Stage 1:

C100.1 will meet the investment need by the need date;

C100.2 adequately reflect the nature and functional capability of the proposed investment;

C100.3 are consistent with the change in the functional capability of the grid as a result of this investment;

C100.4 are consistent with the key assumptions used to determine the MCA; and

C100.5 are likely to provide the expected electricity market benefits related to transmission services.

**Clause C6 – evaluation of the major capex incentive rate**

C101 The major capex incentive rate we set under clause 3.3.5(7)(b) of the Capex IM determines the reward (or penalty) that Transpower receives (or bears) depending on how the actual cost of delivering a major capex project compares to the project's MCA.[283] As noted above, exempt major capex is the amount of the MCA to which the major capex incentive rate does not apply.[284]

C102 Under clause 1.1.5(2) of the Capex IM, the major capex incentive rate is 15% – the default rate – or an alternative rate we specify after considering a request from Transpower.

C103 In evaluating Transpower's proposed major capex incentive rate under clause C6 of Schedule C, we must have regard to at least one of the two factors listed in that provision. We analysed Transpower's proposed major capex incentive rate against the factor in clause C6(a): the magnitude of the cost of Stage 1 relative to the cost of other major capex projects.

C104 The estimated cost of Stage 1 is in the medium range of the costs of previously commissioned major capex projects, which range from $22 million to $853 million.

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

284 Clause 1.1.5(2) of the Capex IM.

C105 Transpower has proposed:[285]

C105.1 a major capex incentive rate of 15%; and

C105.2 that we do not set any exempt major capex rate.

C106 Our decision under clause 3.3.5(7)(b) of the Capex IM is to accept Transpower's proposed major capex incentive rate of 15% for this MCP, but, under clause 3.3.5(7)(c), to set an amount of the MCA that is exempt major capex. Our reasoning for setting an exempt major capex is set out below.

*Our decision on exempt major capex under clause 3.3.5(7)(c) of the Capex IM*

C107 Exempt major capex can be set for portions of the MCA that have high levels of uncertainty. As discussed at paragraphs C67 to C70 and C79 to C82 above, a significant portion of the MCA reflects contingency allowance to cater for the uncertainties Transpower faces in delivering Stage 1.

C108 The effect of exempt major capex is that Transpower does not benefit or suffer a loss from spending the contingency allowance if the risks eventuate. Similarly, the consumers do not have to pay for any reward if the contingency allowance is not spent. This approach is consistent with how we treat uncertainties relating to foreign exchange and inflation forecast error.[286]

C109 Our decision under clause 3.3.5(7)(c) of the Capex IM is to treat the project risk component of the MCA as exempt major capex, equal to $7.9 million in 2022/23 prices. This means that the cost of uncertainties up to this amount will not be subject to the incentive mechanism.

C110 Accordingly, in setting the exempt major capex above, the incentive scheme under clause B3(1) of Schedule B of the Capex IM will work as follows. If the actual cost of delivering Stage 1 is:

C110.1 less than the MCA minus exempt major capex, then applying the major capex incentive rate, Transpower will be entitled to a reward;

C110.2 between the MCA and the MCA minus exempt major capex, then there is no reward or penalty; and

C110.3 more than the MCA, then applying the major capex incentive rate, Transpower will be penalised.

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285 MCP, above n 2, at pg. 44.

286 Clause B3(1) of Schedule B of the Capex IM.

# Attachment D: Evaluation of the investment test

## Purpose of this attachment

D1 In this attachment we present our review of Transpower's application of the investment test. We discuss our evaluation of the parameters Transpower used for the investment test; the expected net electricity market benefits Transpower found; Transpower's selection of the proposed investment; and the results of Transpower's sensitivity analysis.

## Criteria for satisfying the investment test

D2 The investment test set out in Schedule D of the Capex IM uses a cost-benefit analysis using discounting of relevant costs and benefits in the electricity market over a defined calculation period to identify the most economic investment option as the proposed investment.[287]

D3 Under clause D1(1) of Schedule D, a proposed investment satisfies the investment test if it has the highest expected net electricity market benefit and is robust to sensitivity analysis compared with other investment options.

D4 The net expected electricity market benefit:[288]

D4.1 does not need to be positive for the proposed investment to meet the N-1 criterion of the GRS; but

D4.2 needs to be positive for any other proposed investment.

D5 When selecting the proposed investment, Transpower may consider unquantified electricity market benefits or cost elements if the difference in expected net electricity market benefits between two or more investment options is within 10% of the aggregate project costs.[289]

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

D6 Under clause C1(1) of Schedule C of the Capex IM, we are satisfied:

D6.1 with the parameters Transpower used in applying the investment test;

D6.2 that Transpower's proposed investment satisfies the investment test; and

D6.3 that Transpower's proposed investment is robust to sensitivity analysis.

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287 2012 Capex IM reasons paper, above n 4, at para 7.2.1. We note that in our 2017/18 Capex IM review, we decided to retain the investment test criteria and approach in the 2012 Capex IM. See 2017/18 Capex IM review reasons paper, above n 65, at para 194.

288 Clause D1(1)(b) of Schedule D of the Capex IM.

289 Clause D1(1)(c)(ii) and (2) of Schedule D of the Capex IM.

## How the investment test is performed

D7 In carrying out the investment test, Transpower must:[290]

D7.1 estimate the electricity market benefits or cost elements and project costs for each investment option under each relevant generation and demand scenario;[291]

D7.2 calculate the net electricity market benefits for each investment option under each relevant generation and demand scenario. Net electricity market benefit is the sum of the electricity market benefits less the sum of the electricity market costs including the project cost; and

D7.3 calculate the expected net electricity market benefit, which is the weighted average of the net electricity market benefit under each relevant demand and generation scenario.

D8 As part of carrying out the investment test, Transpower must also test whether its proposed investment is sufficiently robust under sensitivity analysis,[292] which verifies whether the proposed investment is robust to changes in some of the key assumptions.

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

D9 Under the Capex IM, we reviewed Transpower's application of the investment test by considering whether:

D9.1 the proposed investment is to meet the N-1 criterion of the GRS or to provide an economic outcome, such as removing network constraints;

D9.2 the parameters of the investment test are appropriate and whether Transpower consulted on the parameters it applied;

D9.3 Transpower reasonably estimated the expected net electricity market benefit of each investment option;

D9.4 the proposed investment is the investment option with the highest net electricity market benefit; and

D9.5 the proposed investment is robust to sensitivity analysis.

D10 We present a summary of our evaluation in the rest of this attachment.

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290 Clause D2 of Schedule D of the Capex IM.

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

292 Clause D1(1)(a) of Schedule D of the Capex IM.

## The MCP's proposed investment is to meet the N-1 criterion of the GRS, but with a partial N-G-1 security level

D11 Under clause D1(1)(b) of Schedule D of the Capex IM, Transpower has submitted the MCP to meet the N-1 criterion of the GRS.

D12 As outlined in our analysis at paragraphs B10 to B14 of Attachment B, we agree with Transpower that by including the post-fault DMS, the proposed investment would provide a partial N-G-1 level of security. Since the proposed partial N-G-1 level of security is higher than that required under the N-1 criterion of the GRS, the proposed investment's expected net electricity market benefit needs to be positive.[293]

D13 Our evaluation confirms that the proposed investment's expected net electricity market benefit is positive.

## Our evaluation of the parameters of the investment test

D14 The Capex IM allows Transpower some discretion to select the analysis parameters of the inputs into the investment test. Transpower is required to consult on the values of the parameters it uses.[294] These parameters are the:

D14.1 demand and generation scenarios (comprising demand forecasts and generation scenarios);[295]

D14.2 discount rate;[296]

D14.3 calculation period;[297]

D14.4 cost per megawatt hour used to determine the value of expected unserved energy;[298] and

D14.5 investment options.[299]

D15 For the reasons we outline below, we are satisfied that Transpower has reasonably selected the investment test parameters.

293 See definition of 'major capex' under clause 1.1.5(2) of the Capex IM and clause D1 of Schedule D of the Capex IM.

294 Clause I4 of the Capex IM.

295 Clause G3(1) of Schedule G of the Capex IM.

296 Clause G4(5) of Schedule G of the Capex IM.

297 Clause G4(5)(b) of Schedule G of Schedule G of the Capex IM.

298 Clause G4(5)(c) of Schedule G of the Capex IM.

299 Clause 7.4.1(2) of the Capex IM.

### Calculation period

D16 Transpower has used a calculation period of 20 years, as the default calculation period under clause G5(11)(b) of Schedule G of the Capex IM. We are satisfied that the default calculation period is appropriate for Stage 1 and there are no clear reasons to consider an alternative period.

### Demand and generation scenarios

D17 The Capex IM requires Transpower to use either the demand and generation forecasts published in EDGS or reasonable variations to those forecasts, having had regarding interested persons' views on these variations.[300]

D18 We present our evaluation of the demand and generation forecasts Transpower used in the investment test below.

*Electricity demand forecasts*

D19 Electricity demand forecasts are used to calculate the expected electricity market benefits of short-listed investment options. The peak demand forecasts discussed in Attachment B are used to predict the need date and future investments of modelled projects. The need dates of modelled projects affect the electricity market cost of investment options.

D20 Table D1 shows the energy demand forecasts for the five EDGS scenarios.[301] The national forecasts are between 46.7 and 70.5 terawatt hours (**TWh**) by 2050 depending on the scenarios.

**Table D1: EDGS scenarios and electricity demand forecast (TWh)**

| EDGS scenario | 2017 | 2035 | 2050 |
|---|---|---|---|
| Reference | 39.7 | 48.4 | 56.7 |
| Growth | 39.7 | 52.0 | 65.1 |
| Global | 39.7 | 44.1 | 46.7 |
| Environmental | 39.7 | 54.3 | 66.5 |
| Disruptive | 39.7 | 55.2 | 70.5 |

300 Clauses D3(1) and (2) of Schedule D of the Capex IM. Under clause I1(1)(b) of Schedule I of the Capex IM, Transpower must consult on each demand and generation scenario variation.

301 EDGS, above n 96, at pg. 23.

D21 Transpower could not use EDGS' demand forecasts because EDGS does not forecast demand by region or point of supply. To overcome this lack of information and to enable calculation of expected electricity market benefits, Transpower used a distribution of demand forecasts from P01 to P99 and averaged the results to estimate the benefits of the investment options.[302]

D22 Transpower used changes in demand forecast in its sensitivity analysis to test the robustness of its results.

D23 We consider that Transpower's approach satisfies the requirements of clause D3 of Schedule D of the Capex IM and is therefore acceptable given the limitations of the data in EDGS.

*Generation scenarios*

D24 A generation scenario is a hypothetical prediction of a set of generation developments within the electricity industry. Generation scenarios are used to determine the timing and need date of a modelled project.

D25 EDGS forecasts generation expansion and decommissioned generation but does not provide information by location in enough detail to use in the investment test. The investment test requires a forecast of generation expansion and decommissioned generation at the regional level. Consequently, the EDGS forecasts cannot be used (without variation) as they do not forecast at a regional level.

D26 EDGS has not forecasted any significant schedulable generation in the WUNI region. Schedulable generation is generation that can be brought into service when required.[303] For the MCP, Transpower used the same generation scenarios as those it used in the short-list consultation.[304]

D27 As discussed in Attachment E of this paper, Transpower also sought submissions in its short-list consultation on its approach to managing market generation commitment in the lifetime of the Project. None of the generators indicated they were contemplating making significant market generation announcements relating to the WUNI region. Transpower considered there was general agreement to its proposed approach to handling any significant market commitments arising.[305]

302 Under clause D3(2) of Schedule D of the Capex IM, Transpower is able to make a reasonable variation to an EDGS scenario provided Transpower consults on that variation (under clause I1(1) of Schedule I of the Capex IM) and reasonably has regard to the views of interested persons. Transpower's EDGS variations are set out in its short-list consultation document and discussed in the MCP, above n 2, at pg. 26. We consider Transpower consulted on and had regard to interested persons' views on its EDGS variation.

303 Wind generation and solar generation are not schedulable.

304 MCP above n 2, *Attachment C Options and Costings report for the MCP* (**MCP options and costing report**), available at: https://comcom.govt.nz/__data/assets/pdf_file/0032/196952/Transpower-WUNIVM-major-capex-proposalAttachment-C-Options-and-costing-report-13-December-2019.pdf, at pgs. 25 to 26.

305 MCP options and costing report, above n 304, at para 5.5; and; MCP stakeholder consultation summary, above n 259, at para 4.2.

D28 We consider that the generation scenarios Transpower used were appropriate given Transpower's short-list consultation did not identify any new schedulable generation in the WUNI region.

**Discount rate for net present value (NPV)**

D29 Transpower used the standard rate of 7% as the discount rate for the MCP and sensitivity tested this with a 10% discount rate in line with clause D7(3)(b) and (c) of Schedule D of the Capex IM, respectively.

**Value of expected unserved energy**

D30 Transpower selected and consulted on a non-standard value of expected unserved energy equal to \$26,500/MWh.[306] Under the definition of 'value of expected unserved energy' in clause 1.1.5(2) of the Capex IM, this figure is non-standard because it is higher than the \$20,000/ MWh specified in 2004 under clause 4(a) of Schedule 12.2 of the Code. \$26,500/MWh is the standard value of expected unserved energy (\$20,000/MWh) inflated at CPI to a 2019 value.

D31 Transpower carried out its sensitivity analysis with values of expected unserved energy of +/- 50% of the \$26,500/MWh figure.

D32 We accept Transpower's approach and use of the non-standard value of expected unserved energy equal to \$26,500/MWh.

**Investment options Transpower considered and consulted on**

D33 The Capex IM requires Transpower to consider and include in its MCP a number of investment options appropriate to the value of the estimated capital expenditure and the complexity of the investment need.[307]

D34 We are satisfied that:

D34.1 the seven investment options Transpower considered in its short-list consultation meet the above requirement under the Capex IM; and

D34.2 the investment options Transpower considered in its short-list consultation were technically feasible solutions that would have met the MCP's investment need.

[306] Clauses I2(2)(c) and I3(3)(d)(iii) of Schedule I of the Capex IM require Transpower to consult in its long-list and short-list consultations on a non-standard value of expected unserved energy Transpower proposes to use. In the short-list consultation, Transpower must also explain why the non-standard value is appropriate.

[307] Clause 7.4.1(2) of the Capex IM.

D35 In developing the investment options, Transpower consulted on and considered 31 long-list ‘components’ to address the investment need, including transmission solutions and NTSs.[308] Transpower’s view was that in the absence of significant new generation in the WUNI region, no single piece of transmission equipment would be able to provide a complete solution by itself, which is why more than one ‘component’ would be required from the long list to meet the investment need.[309] We accept Transpower’s use of this terminology given that the components comprising each investment option in Transpower’s short-list consultation together amounted to a technically feasible solution that would have met the MCP’s investment need.

D36 Transpower classified the long-list options into the following broad categories:[310]

D36.1 NTSs, including demand-side participation;

D36.2 reconfiguration of existing assets;

D36.3 market generation; and

D36.4 new reactive power devices and grid assets.

D37 We reviewed Transpower’s long-list of investment options and the criteria Transpower used to determine these options together with the results of Transpower’s power system studies and demand and generation scenarios. We are satisfied with the long-list of investment options that Transpower considered because they provide a reasonable range of potential solutions that can meet investment need by the need date of the Project.

D38 Transpower refined its long list into a short list of seven investment options using the following screening criteria:[311]

D38.1 fit for purpose;

D38.2 technical feasibility;

D38.3 GEIP;

D38.4 system security; and

D38.5 indicative cost.

D39 We consider the screening criteria are reasonable. The criteria are also consistent with those we use when evaluating an MCP.[312]

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308 Long-list consultation document, above n 46, at pgs. 19-24.

309 MCP options and costing report, above n 304, at pg. 8.

310 Above n 304, at pg. 8.

311 Long-list consultation document, above n 49, at Attachment B, at pg. 54.

312 Clause C2 of Schedule C of the Capex IM.

D40 In line with Transpower's approach to the long-list consultation above paragraph D37, each short-list investment option consisted of installing a set of components rather than one large single component. These included:

D40.1 dynamic reactive plant based on power electronics technology such as STATCOMs and SVCs;

D40.2 static capacitors;

D40.3 series compensation of the BHL-WKM lines; and

D40.4 a post-fault DMS.

D41 Table D2 shows the investment options for Stages 1 and 2 that Transpower considered for detailed analysis.

D42 The investment options consisted of different combinations of the components listed in paragraph D40. Some of the investment options have different investment dates for the components. The different investment dates also affect the grid security standard – N-1 or N-G-1 (or partial N-G-1) – that the relevant investment option would provide.

D43 As discussed in paragraphs C15 to C34, we are satisfied with the technical aspects of the components included in the investment options. The technical aspects we considered were whether the proposed investment and investment options:

D43.1 reflect GEIP;

D43.2 are technically feasible;

D43.3 are able to be implemented in terms of the statutory planning process under the RMA, other regulatory consents, and obtaining property and access rights; and

D43.4 can be integrated into system and market operations.

D44 We note that Transpower did not include synchronous condensers in its short-list consultation. Synchronous condensers are widely used to provide dynamic reactive power. They also have the added advantage of providing inertia and improving the fault levels of the weak networks. However, Transpower's assessment showed that:

D44.1 STATCOMs and SVCs managed transient voltage stability as effectively as synchronous condensers; and

D44.2 synchronous condensers are significantly more expensive than STATCOMs and SVCs.

## Table D2: Investment options for Stages 1 and 2

| Year | Investment options | | | | | | |
|---|---|---|---|---|---|---|---|
| | **Defer investment to 2028** | **Option 1** | **Option 2** | **Option 3** | **Option 4** | **Option 5** | **Option 6** |
| **Grid security standard** | N | N-G-1 | N-G-1 | Partial N-G-1 | N-G-1 | Partial N-G-1 | N |
| **Stage 1** | | | | | | | |
| 2022 | | Pre-fault demand management | Post-fault DMS | Post-fault DMS | 150 MVar DRD at Hamilton | Post-fault DMS | Post-fault DMS |
| 2022 | | | 150 Mvar DRD at Hamilton 110 | 150 Mvar DRD at Hamilton 110 | 150 Mvar DRD at Otahuhu 220 | 150 Mvar DRD at Hamilton 110 | 150 Mvar DRD at Hamilton 110 |
| 2022 | | | 150 Mvar DRD at Otahuhu 220 | 150 Mvar DRD at Otahuhu 220 | Series compensation BHL-WKM lines | 150 Mvar DRD at Otahuhu 220 | 150 Mvar DRD at Otahuhu 220 |
| 2022 | | | Series compensatio n BHL-WKM lines | | 150 Mvar DRD | | |
| 2022 | | | | | 150 Mvar shunt capacitors | | |
| **Stage 2** | | | | | | | |
| 2023 | | | | Series compensatio n BHL-WKM lines | 150 Mvar DRD | 150 Mvar DRD | |
| 2023 | | | | | 75 Mvar shunt capacitors | 150 Mvar shunt capacitors | |
| **Modelled projects** | DRDs, OHW bussing | DRDs, OHW bussing | DRD, OHW tee | DRDs, OHW tee | DRD, OHW tee | DRD, OHW bussing | DRD, OHW bussing |

## Our evaluation of the expected net electricity market benefits of each investment option

D45 In applying the investment test, Transpower must calculate the following for each investment option included in the MCP:

D45.1 the electricity market benefits under the relevant demand and generation scenario;

D45.2 the electricity market costs under the relevant demand and generation scenario;

D45.3 the net electricity market benefit; and

D45.4 the expected net electricity market benefit.

D46 Under Schedule D of the Capex IM:

D46.1 'electricity market benefit or cost element' means any of the market benefits received or market costs incurred by consumers during the calculation period under the relevant demand and generation scenario that will affect net electricity market benefits;[313]

D46.2 the 'net electricity market benefit' is, in respect of an investment option applied to a demand and generation scenario, its aggregated quantum of each electricity market benefit or cost element less its aggregated quantum of each project cost;[314] and

D46.3 the 'expected net electricity market benefit', in respect of an investment option, is the weighted average of the net electricity market benefit under each relevant demand and generation scenario.[315]

D47 In evaluating Transpower's application of the investment test, we have assessed whether Transpower reasonably estimated for each investment option in the MCP:

D47.1 the electricity market benefits;

D47.2 the electricity market costs; and

D47.3 the net electricity market benefit and the expected net electricity market benefit.

313 Clause D4(1) of the Capex IM.

314 Clause D2(2) of the Capex IM.

315 Clause D2(1) of the Capex IM.

**Our evaluation of Transpower's calculations of the electricity market benefit**

D48 Transpower considered and assessed the following two categories of electricity market benefits as the most relevant to the MCP's proposed investment:

D48.1 avoidance of 'the cost of involuntary demand curtailment borne by end users of electricity' or the 'cost of unserved energy';[316] and

D48.2 reduction of transmission losses.[317]

D49 We are satisfied that these two categories of electricity market benefit are the most relevant to the proposed investment.

D50 In their submissions on Transpower's short-list consultation, Contact and Genesis indicated that there would be some competition benefits provided by the proposed investment.[318]

D51 Transpower did not attempt to quantify competition benefits, but instead assessed competition benefits as unquantified benefits, noting particularly that increasing the WUNI region's transmission capability will enable competition to be maintained in the electricity market following thermal decommissioning and expected demand growth.[319]

D52 We acknowledge that there would be increased competition benefits if market constraints are reduced but consider that factoring in competition benefits is unlikely to affect Transpower's ranking of the investment options.

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316 Clause D4(1)(b) of the Capex IM.

317 Clause D4(1)(g) of the Capex IM.

318 Contact, *Waikato and Upper North Island Voltage Management consultation*, 22 July 2019, at Q7, Appendix 1, available at: https://www.transpower.co.nz/sites/default/files/plain-page/attachments/Contact%20-%20Waikato%20and%20Upper%20North%20Island%20Voltage%20Management%20submission_0.pdf; Mercury, *Waikato and Upper North Island Voltage Management Investigation – Short List Investment Options*, 22 July 2019, at Q7, pg. 3, available at: https://www.transpower.co.nz/sites/default/files/plain-page/attachments/Mercury%20-%20Waikato%20and%20Upper%20North%20Island%20Voltage%20Management%20submission_0.pdf; and; MCP stakeholder consultation summary, above n 259, at para 4.7.

319 MCP options and costing report, above n 304, at pgs. 36 and 37.

*Estimating the cost of involuntary demand curtailment*

D53 Avoiding the cost of involuntary demand curtailment is the main benefit of the Project. There are several methods for estimating this cost, including:

D53.1 *System collapse*: one method is to assume that all demand, up to the thermal limit of the grid, is supplied.[320] Then, if demand is above the voltage stability limit and there is critical fault at that time, the system collapses causing a blackout (system collapse). The expected avoided loss of electricity supply is an estimate of the amount of unserved energy during the system collapse.

D53.2 *Demand shedding*: another method is to assume that the system operator keeps demand within the voltage stability limits. In this case, the system operator curtails any demand above the voltage stability limit (demand shedding). The expected benefits of an investment are the expected cost of this involuntary demand curtailment – ie, the demand shed.

D53.3 *Hybrid approach*: a third method is a hybrid of the first two approaches. The hybrid approach assumes that the system operator carries some risk and supplies some demand above the voltage stability limits, but when the probability of a voltage collapse becomes too high, the system operator sheds any extra demand.

*Transpower's approach to assessing the involuntary demand curtailment*

D54 Transpower assessed the involuntary demand curtailment using the system collapse approach, involving an assessment of the risk of a system collapse and the demand that would be lost as a consequence. A summary of Transpower's approach is as follows:[321]

D54.1 Transpower used the fault rates of relevant assets to determine the risk of a system collapse, which Transpower derived as follows:[322]

D54.1.1 the fault rates for Unit 5 and the Otahuhu-Whakamaru circuits are based in historical performance of these assets;

D54.1.2 the fault rate for the dynamic reactive plant is based on historical performance of SVCs and STATCOMs;

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[320] The thermal limit of the grid is reached when electricity flowing in an asset connected to the grid is above the asset's rating. Transmission operators normally set the thermal limit so that a major asset can disconnect from the grid but electricity flowing through the asset is then rerouted via the remaining assets. Thermal limit is set so none of the remaining assets overload.

[321] MCP options and costing report, above n 304, at Appendix 2.

[322] Above n 304, at Appendix 2, pgs. 54 and 55.

D54.1.3 the fault rates for other 220kV transmission circuits, including the BHL-WKM lines, are based on historical performance of these assets; and

D54.1.4 the fault rate for the BHL-PAK cable is based on international statistics from CIGRE.[323]

D54.2 Not all faults on transmission lines will result in a voltage collapse. The fault must be two-phase to ground or worse, and it must be within 5 km of the substation at either end of the relevant circuit. Transpower assumed that 6% of all faults are two-phase to ground or worse;[324] and

D54.3 Transpower used the above two assumptions to estimate the probabilities of failure.[325]

D55 We are satisfied with Transpower's assessment of the risk of failure.

D56 The quantified electricity market benefits Transpower calculated for the MCP's different investment options are set out in Table 12 of the MCP options and costing report.[326]

D57 The net electricity market benefits and electricity market benefits for each investment option in the table are depicted alongside a 'defer investment option'. However, under clause G4(2) of Schedule G of the Capex IM, the MCP should have specified the absolute values of these benefits to confirm that the expected net electricity market benefit for the proposed investment is positive.[327]

D58 Transpower later provided us a spreadsheet of the absolute values of the electricity market benefits for each investment option, which are shown below in Table D3.

*Transpower's approach to assessing the benefit of the reduction in transmission losses*

D59 The benefit from the reduction in transmission losses from delivering Stage 1 is small compared to the benefit of avoiding the cost of involuntary demand curtailment.

D60 Transpower's assessment is that the benefit of the reduction in transmission losses is less than 1.4% of the benefit of avoiding the cost of involuntary demand curtailment.

D61 We did not evaluate Transpower's assessment of this benefit because the benefit does not have a material impact on the results of the investment test.

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323 When assessing the risk of failure, we used the design fault rate for the BHL-WKM lines, rather than the design fault rate that Transpower used. This is because the BHL-WKM lines are designed to be highly reliable.

324 MCP options and costing report, above n 304, at Appendix 2, pg. 55.

325 Above n 304, at pg. 55, Table A2-5.

326 Above n 304, at pgs. 33, 34 to 35, and 39.

327 Under clause D2(2) of Schedule D of the Capex IM, 'net electricity market benefit' means, in respect of an investment option applied to a demand and generation scenario, its aggregated quantum of each electricity market benefit or cost element less its aggregated quantum of each project cost.

**Table D3: Transpower's calculation of the electricity market benefits ($ million) of each investment option for Stage 1**

| | **Defer investment to 2028** | **Option 1** pre-fault demand management as an NTS | **Option 2** post-fault DMS, 2x DRDs, series caps | **Option 3** post-fault DMS, 2x DRDs, | **Option 4** 3x DRDs, series caps, shunt caps | **Option 5** post-fault DMS, 2x DRDs[328] | **Option 6** post-fault DMS, 2x DRDs |
|---|---|---|---|---|---|---|---|
| **Expected unserved energy** | 2,053 | 2,253 | 2,228 | 2,225 | 2,245 | 2,223 | 2,180 |
| **Reduction in transmission losses** | 0 | 0 | 32 | 30 | 32 | 0 | 0 |
| **Total benefits** | 2,053 | 2,253 | 2,260 | 2,255 | 2,278 | 2,223 | 2,180 |

*Our evaluation of Transpower's assessment of the value of the expected unserved energy*

D62 In evaluating Transpower's assessment and calculation of the electricity market benefits of each investment option in the MCP, we did not seek to replicate Transpower's results. Rather, we tested Transpower's results by using the demand-shedding approach described above, which we consider is simpler and provides a reasonable cross-check on Transpower's approach.

D63 The demand-shedding method we used evaluates the expected unserved energy of investment option 1: pre-fault demand management as an NTS (**pre-fault DM**). We consider it is adequate to test one option because:

D63.1 as shown in Table D3 above, the expected unserved energy benefits of all investment options are within a range of 8% of each other; and

D63.2 the differences in the expected unserved energy shown in Table D3 for each investment option are due to the timing differences of the investments of modelled projects within the calculation period. The assumed investment dates are shown in Table D2 above. In our evaluation, we assume there will be no modelled projects so the expected unserved energy values for all investment options will be the same.

D64 We evaluated Transpower's assessment of the cost of involuntary demand curtailment for option 1 by:

D64.1 limiting the half-hourly demand to Transpower's N-1 load limit;

[328] Options 3, 4 and 5 have different components for Stage 2.

D64.2 using EDGS' demand forecasts to estimate the rate of growth for each of the EDGS scenarios and then using these rates to forecast demand growth in the WUNI region for every half hour;

D64.3 using the actual half-hourly demand for winter 2019 as the base year for forecasting demand,[329] we forecasted demand until 2040;

D64.4 assuming that demand is constant over each respective half-hour period;

D64.5 estimating the involuntary demand curtailment for each half-hour period as the difference between the forecast demand for that half-hour period and the N-1 load limit. Whenever demand exceeds the N-1 load limit, some of the demand is curtailed; and

D64.6 using a value of unserved energy of $20,000/ MWh to determine the value of the involuntary demand curtailment.

D65 Our assessment estimates the net electricity market benefit of option 1 at approximately $8,700 million, while the net electricity market benefit Transpower estimated is $2,200 million. The reasons for the difference in the two estimates are:

D65.1 we based our calculation on the assumption that no demand above the voltage stability limit is served over the calculation period. This results in a much higher amount of unserved energy and therefore value of involuntary demand curtailment; and

D65.2 Transpower assumes that the transmission network will continue to supply demand and demand would only curtail if there was a fault that caused a system collapse. Since the probability of such faults is low, most of the time demand above the voltage stability limit is supplied without any incidents.

D66 We are satisfied that Transpower's assessment of the benefits is reasonable. Our assessment confirms that the expected net electricity market benefits of the MCP's proposed investment are significantly higher than the expected net electricity market costs.

### Our evaluation of Transpower's assessment of the electricity market cost

D67 Clause D4(1) of the Capex IM defines electricity market cost element as market costs incurred by consumers during the calculation period under the relevant demand and generation scenario that will affect net electricity market benefits. Clause D4(1) of the Capex IM provides a list of these costs.

D68 Under clause D4(1) of Schedule D of the Capex IM, Transpower identified the following electricity market cost elements for Stage 1:

D68.1 the capital cost of the investment options and the proposed investment;

329 Electricity Market Information website, https://www.emi.ea.govt.nz/Wholesale/Reports/.

D68.2 the capital cost of modelled projects over the calculation period;

D68.3 operating and maintenance costs of all potential investment over the calculation period; and

D68.4 cost of ancillary services including system operator costs over the calculation period.

*Evaluation of the capital costs of the proposed investment*

D69 We discussed our approach to evaluating the capital cost of the proposed investment at paragraphs C52 to C87 of Attachment C.

*Evaluation of the capital costs of other investment options for Stage 1*

D70 A post-fault DMS and the DRDs are common to most of the investment options. The capital costs for these assets were assessed as part of assessing the capital costs of the investment options.

D71 The assets that are in the investment options but not in the proposed investments are:

D71.1 series compensation of the BHL-WKM lines;

D71.2 shunt capacitors; and

D71.3 pre-fault DM.

D72 We evaluated the costs of the above assets in a similar manner to how we evaluated the capital cost of the proposed investment for Stage 1, noting that there is less information available on the costs of these assets.

D73 We also note that series compensation of the BHL-WKM lines is the likely proposed investment for Stage 2 at this point, but this may change as Transpower develops its major capex proposal for Stage 2.

*Evaluation of the estimated costs of modelled projects*

D74 As seen in Table D2 above, the modelled projects consist of:

D74.1 SVCs;

D74.2 Ohinewai (**OHW**) bussing; and

D74.3 OHW tee.

D75 The cost of SVCs is included in the cost of the proposed investment as one of the two DRDs.

D76 We assessed the estimated capital cost of OHW bussing and OHW tee modelled projects using costs from similar previous projects.[330]

D77 Modelled projects are at an early stage of their lifecycle. This means that the scope and estimated costs of the above modelled projects are therefore preliminary in nature but of similar levels of accuracy to most of the MCP's investment options. Consequently, the accuracy of the cost estimates for the modelled projects does not have a material impact on the ranking of the investment options.

*Evaluation of operating and maintenance costs*

D78 Transpower based its estimate of the operating and maintenance costs (**O&M**) of each investment option on its experience and historical data, estimating an O&M cost of 1% of the capital cost of each component of each investment option.[331]

D79 In its submission on the short-listed consultation, WEL Networks Limited (**WEL**) considered that:[332]

> [Transpower's estimate of the investment options'] O&M costs in Table 11 [of the short-list consultation document] seem low. In comparison, the annual Maintenance Recovery Rate for substation equipment in the TPM is around 1.74% of replacement cost.

D80 We acknowledge WEL's submission but consider that Transpower's estimated O&M costs are in line with Transpower's previous O&M cost estimates.[333] We consider this is appropriate given the O&M cost estimates are low compared to the relevant capital costs and because any inaccuracies in the O&M cost estimates are unlikely to affect the ranking of the different investment options.

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330 Transpower's Upper South Island grid upgrade – Stage 2 project had similar forecast costs for bussing and tee connections. Information on Stages 1 and 2 of the Upper South Island grid upgrade project is available at: https://comcom.govt.nz/regulated-industries/electricity-lines/electricity-transmission/transpower-capital-investment-proposals/transpower-major-capital-proposal/upper-south-island-grid-upgrade-stage-1; and; https://www.transpower.co.nz/upper-south-island-grid-upgrade-resources.

331 MCP options and costing report, above n 300, at pg. 27.

332 WEL, *Submission on the Waikato and Upper North Island Voltage Management Consultation*, 22 July 2019, at Appendix, Q6, available at: https://www.transpower.co.nz/sites/default/files/plain-page/attachments/WEL%20Networks%20-%20Waikato%20and%20Upper%20North%20Island%20Voltage%20Management%20submission_0.pdf.

333 The Upper South Island grid upgrade – Stage 2 project, and other previous projects, estimate O&M costs of 1% of the capital cost of each component of the relevant investment.

*Our review of the net electricity market benefits and expected net electricity market benefits*

D81 In carrying out the investment test, Transpower must assess the expected net electricity market benefit of each investment option over the range of future electricity market scenarios in the EDGS.[334] As discussed at paragraph D21 above, EDGS does not forecast at the regional level necessary for this analysis. To overcome this, Transpower adapted the EDGS with reasonable variations and used a distribution of demand forecasts from P01 to P99. Transpower then averaged the results of the analysis to estimate the net electricity market benefits of the investment options.[335]

D82 Transpower's approach provided a much larger range of demand growth scenarios than the five EDGS scenarios. We are satisfied that Transpower's approach meets, and exceeds, the requirements of the Capex IM.

D83 Table D4 below set out the results of our evaluation of Transpower's application of the investment test to the investment options for Stages 1 and 2. The values in our table are different from those set out in Table D3 (which shows Transpower's equivalent values) because Transpower calculated and depicted some of the investment options' electricity market benefit and cost elements relative to a 'defer investment option'. Transpower also displayed the cost of modelled projects as benefits relative to the cost of the 'defer investment' option, whereas we have displayed absolute values for these.

**Table D4: Expected net electricity market benefits for Stages 1 and 2 ($ million)**

| | Defer investment to 2028 | Option 1 Pre-fault DM as an NTS | Option 2 post-fault DMS, 2xSVC, series cap | **Option 3 post-fault DMS, 2xSVC** | Option 4 3xSVC, series cap, shunt cap | Option 5 post-fault DMS, 2xSVC[336] | Option 6 Post-fault DMS, 2xSVC |
|---|---|---|---|---|---|---|---|
| ***Expected net electricity market costs*** | | | | | | | |
| Stage 1 capital cost | | | 174 | **96** | 219 | 96 | 96 |
| Stage 2 capital cost | | | | **72** | 47 | 48 | |
| Stages 1 and 2 O&M | - | 782 | 20 | **19** | 30 | 16 | 11 |
| Modelled projects | 280 | 363 | 138 | **138** | 115 | 217 | 237 |
| Total | 280 | 1,145 | 331 | **326** | 410 | 378 | 345 |

334 clauses D1(1), D2(1), and D3(1) of Schedule D of the Capex IM.

335 MCP options and costing report, above n 304, at paras 4.1.1.4, 4.1.1.5, and 4.1.3 to 4.1.5.

336 Options 3, 5 and 6 have different Stage 2 major capex project outputs.

| | Defer investment to 2028 | Option 1 Pre-fault DM as an NTS | Option 2 post-fault DMS, 2xSVC, series cap | **Option 3 post-fault DMS, 2xSVC** | Option 4 3xSVC, series cap, shunt cap | Option 5 post-fault DMS, 2xSVC[336] | Option 6 Post-fault DMS, 2xSVC |
|---|---|---|---|---|---|---|---|
| ***Expected electricity market benefits*** | | | | | | | |
| Preventing involuntary demand curtailment | 2,053 | 2,253 | 2,228 | **2,225** | 2,245 | 2,223 | 2,180 |
| Reduction in transmission losses | 0 | 0 | 32 | **30** | 32 | 0 | 0 |
| Total | 2,053 | 2,253 | 2,260 | **2,255** | 2,278 | 2,223 | 2,180 |
| ***Expected net electricity market benefits*** | | | | | | | |
| | 1,774 | 1,107 | 1,928 | **1,929** | 1,867 | 1,845 | 1,835 |

D84 Transpower selected option 3 as the proposed investment for the MCP.

## Transpower's selection of the proposed investment is consistent with the Capex IM

D85 We are satisfied that Transpower correctly applied the investment test and related Capex IM requirements in selecting option 3 as the proposed investment for the MCP.

D86 As shown in Tables D3 and D4 above, options 2 and 3 have the highest expected net electricity market benefits, with little between them. Transpower analysed the unquantifiable benefits of each of the two options to select option 3 as the proposed investment.[337]

D87 The main difference between options 2 and 3 is that option 3 includes a post-fault DMS while option 2 would see the more expensive series capacitors installed at Stage 1.

D88 For the above reason, option 3 has a much lower capital cost ($96 million) for Stage 1 compared to option 2 ($174 million), in NPV terms.

D89 Option 3 also provides Transpower the flexibility to respond to movements in the electricity market when considering investment options for Stage 2. For example, if peak demand reduces in the WUNI region, Stage 2 can be delayed.

337 MCP, above n 2, at para 4.

D90 Similarly, under option 3, Transpower would defer delivering the series capacitors to Stage 2. Transpower preferred the greater optionality that option 3 provides. Under option 2, delivering the series capacitors at Stage 1 risks commissioning them earlier than they would be needed if the Rankines remain in normal service. We agree with Transpower's view.[338]

D91 We therefore consider that, based on its lower capital cost, option 3 is the more appropriate proposed investment for Stage 1 than option 2.

## The proposed investment is robust to sensitivity analysis

D92 The Capex IM requires Transpower to perform a sensitivity analysis to test whether the proposed investment is robust to some of the key assumptions.[339] The Capex IM also lists the parameters that must be varied to assess whether the results of the investment test are robust to variations.[340] These parameters reflect the key assumptions that can have a significant impact on the results of the investment test.

D93 Table D5 below sets out the parameters Transpower applied for its sensitivity analysis and our assessment of them.

D94 We assessed the robustness of the proposed investment by considering whether option 3 provided the highest electricity market benefit under most of Transpower's parameters.

D95 As outlined in Table D5, we are satisfied that the parameters Transpower used for its sensitivity analysis are reasonable. The results of Transpower's sensitivity analysis show that options 2 and 3 retain the highest expected net electricity market benefits for all parameters of the sensitivity analysis except for the 'late retirement from normal service' of the Rankines. This outcome is expected given that the Rankines' potential removal from normal service is key aspect of the investment need underpinning the MCP.

D96 We are satisfied that Transpower's sensitivity analysis confirms that the proposed investment for Stage 1 is robust to sensitivity analysis.[341]

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338 MCP, above 2, at pg. 11.

339 Clause D7 of the Capex IM.

340 Clause D7(1) of the Capex IM.

341 MCP options and costing report, above n 304, at pg. 34.

### Table D5: Parameters Transpower used for sensitivity analysis and our assessment

| Parameter under Schedule D of the Capex IM | Included/not included in sensitivity analysis | Our assessment |
|---|---|---|
| Clause D7(1)(a) – forecast demand | Performed analysis for the five EDGS scenarios as this represents potential variations in demand growth. | Reasonable given Transpower used a demand distribution and used the average to assess the expected market benefits, |
| Clause D7(1)(b) the size, timing, location, fuel costs and operating and maintenance costs, relevant to existing assets, committed projects, modelled projects and the investment option in question | Included given Unit 5 remains in normal service | Reasonable. The availability of Unit 5 has a significant impact on the expected market benefits |
| Clause D7(1)(c) – the capital cost of the investment option in question and modelled projects | Included as upper range and lower range of capital cost estimate | Reasonable. The two ranges are high and reflect the actual costs from other previous projects |
| Clause D7(1)(d) – the timing of decommissioning, removing or de-rating of decommissioned assets | Included in the event of the Rankines retiring from normal service in 2030 instead of 2022 as assumed for Stage 1 | Reasonable as the Rankines' future and potential removal from normal service is a key aspect of the investment need underpinning the MCP |
| Clause D7(1)(e) – the value of unserved energy | Varies value of unserved energy by +50% and -50% | Reasonable as this covers a wide range for the value of unserved energy |
| Clause D7(1)(f) – discount rate | Included as 4% and 10% | As required in the investment test[342] |
| Clause D7(1)(g) – range of hydrological inflow sequences | Not included | Reasonable. This parameter is relevant to the calculation of loss benefits. Transpower determined the average of loss benefits across 84 historical inflow sequences. We agree that assessing one hydro inflow would not provide any relevant information |
| Clause D7(1)(h) – relevant demand and generation scenario probability weightings | Not included | Reasonable |
| Clause D7(1)(i) – competition effects of the investment option in question | Not included | While there may be competition benefits, we consider it reasonable to not include competition benefits for the reasons mentioned above |
| Clause D7(1)(j) – other variables that Transpower considers uncertain | Considered voltage contingency as 100% probability and -50% probability | Reasonable given that the probability of voltage collapse is among the key variables affecting the MCP's electricity market benefits |

342 Clause D7(3) of the Capex IM.

# Attachment E: Summary and assessment of Transpower's consultation in preparing the MCP

E1 Transpower must consult with stakeholders on the matters and in accordance with the requirements specified in Schedule I of the Capex IM, which includes inviting interested parties to propose NTSs that would meet the investment need.[343]

E2 Under clause I1 of Schedule I, Transpower must consult on the following matters:

E2.1 the investment need;

E2.2 each demand and generation scenario variation;

E2.3 key assumptions;

E2.4 a long list of options including any potential NTSs; and

E2.5 a short list of options including the results of the investment test.

E3 In July 2016, in line with clause I2 of Schedule I, Transpower carried out its long-list consultation, which included inviting information on NTSs.

E4 In June 2019, in line with clause I3 of Schedule I, Transpower carried out its short-list consultation.

E5 This attachment summarises the submissions on these consultations, our assessment on the extent to which Transpower has taken the submissions into consideration in developing the MCP, and whether Transpower satisfied the requirements of Schedule I of the Capex IM.

E6 Table E1 below lists the documents that Transpower used in these consultations.

[343] Clause I5 of Schedule I of the Capex IM sets out the approach to consideration and consultation on NTSs to meet the investment need.

**Table E1: Transpower's consultation documents[344]**

| Document name and web location |
|---|
| **Long-list consultation July 2016** |
| Waikato and Upper North Island Voltage Management Long-List Consultation July 2016 |
| **Short-list consultation June 2019** |
| Waikato and Upper North Island Voltage Management Short-List Consultation June 2019 |
| Attachment A: Power System Analysis Report June 2019 |
| Attachment B: Options and Costing Report June 2019 |
| **Further RFI on NTSs - 2 October 2019** |
| https://www.gets.govt.nz/TNZ/ExternalTenderDetails.htm?id=21708670 |

## Long-list consultation

E7 The long-list consultation document included:

E7.1 information on the investment need;

E7.2 Transpower's assumptions on demand and generation;

E7.3 a list of components that could provide potential solutions, including NTSs;

E7.4 Transpower's approach to considering NTSs;

E7.5 the process Transpower would use to develop the MCP; and

E7.6 an invitation for information on NTSs.[345]

E8 We assessed whether the information in the consultation document complied with the Capex IM requirements and how Transpower considered them when developing the proposal.

E9 We are satisfied that Transpower's long-list consultation met the requirements of the Capex IM. A summary of the submissions and our assessment follows.

[344] These documents are available at https://www.transpower.co.nz/waikato-and-upper-north-island-voltage-management-investigation.

[345] All submissions on the long-list consultation and Transpower's summary of submissions are available on https://www.transpower.co.nz/waikato-and-upper-north-island-voltage-management-submissions.

## The investment need

E10 The following stakeholders submitted on the investment need:

E10.1 Auckland City Council, Contact, Counties Power Limited (**Counties Power**), Genesis, Mercury, and Northpower Limited (**Northpower**) stated that they agreed with the investment need;

E10.2 Auckland City Council submitted that other issues, such the Electricity Authority's review of the TPM and distributed generation pricing principles,[346] should be considered;

E10.3 Contact submitted that Unit 5 is a more onerous N-1 contingency risk;

E10.4 Counties Power sought clarification from Transpower on voltage stability limits;

E10.5 Northpower considered that since the investment need is driven by generators' decisions, the generators would be the beneficiaries of the Project and should therefore be allocated the transmission charges relating to the Project under the TPM's benefit-based charge (which was still to be finalised at the time);

E10.6 MEUG agreed that an investment would be required as demand increases; and

E10.7 Vector stated that it did not support the Project while the TPM was under review.

E11 We note that the main beneficiaries of the Project – namely Auckland City Council, Counties Power and Northpower – recognised that the Project is needed. Vector said that it did not support the Project while the TPM was under review, but Vector did not offer any alternatives and did not state that it disagreed with the need for the Project.

E12 We note that the TPM does not affect an MCP or our evaluation of it, including our assessment of the investment test under Schedule D of the Capex IM. The TPM does, however, determine the allocation of transmission charges to consumers for the recovery of an approved major capex project.

## Responses on assumptions on demand and generation

E13 Alongside the Rankines' potential removal from normal service, Transpower's assumptions on demand and generation also drive the need for the Project. When assessing the need for Stage 1, we assessed whether Transpower had adequately considered the issues submitters raised on Transpower's demand and generation assumptions.

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346 The distributed generation pricing principles are set out in clause 2 of Schedule 6.4 of the Code.

*Generation uncertainties*

E14 Transpower consulted on its approach to deal with uncertainties in generation. This MCP is based on the assumptions that the Rankines will be decommissioned by the end of 2022 and there will be no new suitable generation installed as a replacement in the WUNI region.[347] These assumptions may change as the relevant information available changes. Transpower stated that it will adapt the MCP or seek an amendment to an approved major capex project output if these assumptions change.[348]

E15 Most of the submitters agreed with the approach to managing market uncertainties.

E16 Genesis submitted the MCP should be structured with a degree of flexibility such that NTSs are prioritised until generation decisions are committed.[349]

*Demand forecast*

E17 The following stakeholders responded to the long-list consultation's content on Transpower's assumptions about demand forecast:[350]

E17.1 Contact, Counties Power, and Mercury agreed with Transpower's demand forecasts. Contact noted that net peak demand could increase if the Electricity Authority finalised its TPM proposal.

E17.2 MEUG and Genesis considered that the demand forecasts were high.

E17.3 Northpower submitted that the proposed TPM would affect demand and suggested that Transpower consider higher peak and lower peak scenarios.

E17.4 Top Energy Limited (**Top Energy**) submitted that Transpower should consider a higher peak demand because the (then) proposed changes to the TPM and distributed generation pricing principles would reduce the incentive to control or manage peak demand.

E17.5 Vector also submitted that potential changes to the TPM's interconnection charge, which at the time was based on regional coincident peak demand, could have a step effect on demand.

E18 As expected, submitters' views on Transpower's demand forecast varied. As Transpower developed the MCP, it considered the trends in demand and revised its forecast in the short-list consultation.

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347 MCP, above n 2, at para 2.3.

348 MCP, above n 2, at pg. 12.

349 Genesis, *Waikato and Upper North Island Voltage Management Short List consultation*, 22 July 2019, at pgs. 1 and 2, available at: https://www.transpower.co.nz/sites/default/files/plain-page/attachments/WUNIVM%20Submission%20Aug%2016%20-%20Genesis.pdf.

350 We note that Transpower revised its demand forecast since the long-list consultation and this deferred the Stage 1 need date. We used EDGS to assess the need date of Stage 1.

E19 In its MCP, Transpower refreshed its demand forecast based on the assumptions and forecasts in EDGS. We have discussed this in Attachment B of this paper.

**List of components that can provide potential solutions**

E20 Transpower recognised that potential investment options would likely combine different assets installed over a period. In the long-list consultation document, Transpower provided the following categories of components that could provide potential solutions:

E20.1 eight components as options for transmission solutions;

E20.2 six components that could be either transmission solutions or NTSs;[351] and

E20.3 five categories of potential NTSs, including voltage support devices, market or embedded generation, and demand management.[352]

E21 Submitters did not provide any suggestions on transmission solutions except that Contact questioned whether series capacitors could be used on the Huntly-Stratford circuits to reduce the impedance of that line. Transpower responded, and we agree, that using series capacitors to reduce the impedance on the Huntly-Stratford circuits would not materially help resolve the voltage stability issues in the WUNI region.[353]

**Responses to first RFI on NTSs**

E22 In response to Transpower's first RFI (included in the long-list consultation document) on NTSs, NTS proponents proposed the following NTSs:

E22.1 synchronous condensers;

E22.2 batteries combined with renewable generation;[354]

E22.3 batteries with options to provide multiple services;[355, 356]

E22.4 hybrid STATCOM/ battery solutions;[357]

351 These components include reactive support devices and grid scale batteries, which could either be provided by Transpower (transmission solution) or a third party which would be considered an NTS.

352 Long-list consultation document, above n 49, at pgs. 19 and 30.

353 MCP stakeholder consultation summary, above n 259, at para 2.2.6.

354 Auckland City Council proposed this as an option rather than an NTS it would provide.

355 Mitsubishi New Zealand Limited, Contact and Counties Power.

356 Contact submitted that Transpower should consider the extent to which the Capex IM should create a separate NTS cost allowance for energy storage. We note that the Capex IM already has a cost recovery regime for NTSs that replace or defer investments in transmission assets. Under the Capex IM's investment test, Transpower must deliver the solution with the highest net electricity market benefit. The investment test does not discriminate between a transmission solution or an NTS.

357 Siemens Limited provided information on its hybrid STATCOM/battery solution, noting that this is an evolving technology.

E22.5 dynamic reactive support via grid support contracts (**GSC**);[358]

E22.6 embedded generation;[359]

E22.7 market generation under a GSC;[360,]

E22.8 bringing forward the commissioning date of Ngawha generation plant;[361] and

E22.9 reducing peak demand under a GSC.[362]

*Batteries*

E23 While submissions on NTSs touched on grid-scale batteries and solutions including batteries, no proponent offered a complete operational batteries-based solution that would meet the investment need.

E24 In short-listing the components and developing the investment options, Transpower concluded that batteries were very expensive as a transmission-only solution. We also note that batteries have been economical when deployed to provide multiple services. However, Transpower is limited in the range of services it can provide using its assets including batteries.

*Synchronous condensers*

E25 Genesis offered to explore with Transpower the scope for converting the Rankines into synchronous condensers.[363]

E26 Mercury provided confidential information to Transpower on the high-level feasibility and costs associated with converting its Southdown generators to synchronous condensers.

## Short-list consultation

E27 Transpower carried out its short-list consultation in June 2019. This consultation included information on the investment need, demand and generation scenarios, investment options and the proposed investment, provisional major capex project outputs, and the application of the investment test.

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358 Mercury provided information on the potential scope to convert its Southdown generators to synchronous condensers. Electrix Limited advised it has the expertise to convert the decommissioned thermal generators at Otahuhu to synchronous condensers. Contact noted that GSCs should be for terms longer than three years to ensure the most efficient outcomes for end consumers.

359 Electra Generation Limited proposed distributed peaker generation plants.

360 Genesis provided some information on the scope for retaining the Rankines as generators. For its part, Contact considered that offering GSCs to generators who modify their plans to meet Transpower's requirements would not deliver efficient market outcomes.

361 Top Energy proposed bringing forward the commissioning dates for Ngawha generation under a GSC. Transpower undertook to discuss this.

362 Auckland City Council recommended a focus on reduction of peak load via a range of solutions such as increased efficiency of appliances and buildings, demand shifting of local loads.

363 MCP stakeholder consultation summary, above n 259, at pgs. 12-13.

E28 We are satisfied that Transpower's short-list consultation complied with the requirements of Schedule I of the Capex IM.

E29 Submissions on Transpower's long-list and short-list consultations – particularly those on the investment need, demand and generation scenarios, and investment options – assisted our evaluation of Stage 1 under the Capex IM. We have discussed demand and generation scenarios and the investment test in Attachment D of this paper. We provided our views on the major capex project outputs in Attachment C of this paper. We discuss Transpower's treatment of peak demand below.

**Demand and generation scenarios**

E30 Transpower advises that after its short-list consultation, it incorporated the latest EDGS into its peak demand analysis and updated its models to reflect 2018 actual peak demand.[364] This increased the peak demand forecast and brought forward the need date of the proposed investment.[365]

E31 A summary of our assessment of submissions on the investment need and investment options is set out below.

**Investment need**

E32 Transpower's consultation on investment need in the short-list consultation included a question on whether interested parties agreed with Transpower's assumptions on voltage stability, particularly on the extent and expected response of voltage sensitive loads. Interested parties made the following submissions on this matter:

E32.1 Contact, Counties Power, Genesis, Mercury, agreed with Transpower's assumptions.

E32.2 The Lines Company Limited (**TLC**) submitted that Transpower is the custodian of New Zealand's electricity grid, charged with connecting New Zealanders "to their power system, through safe, smart solutions for today and tomorrow". Hence, Transpower is fully responsible for the power system's integrity, which may from time to time require Transpower to invest and ensure the system's adequate performance.[366]

E32.3 Meridian stated that it continued to support identification of and investment in components that will maintain voltage stability in the transmission network. Meridian agrees with Transpower that the long lead times required to commission transmission equipment make it essential that the investigation for Stage 1 proceed at pace despite the uncertain market conditions.[367]

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364 MCP, above n 2, at para 3.1.

365 MCP, above n 2, at pg. 6.

366 TLC, *Waikato and Upper North Island Voltage Management Consultation*, 25 July 2019, at pg. 1.

367 Meridian, *Waikato and Upper North Island Voltage Management investigation*, 19 July 2019, at pg. 1.

E32.4 Vector submitted that Transpower needed to verify its assumptions about sensitive load against actual observed response to voltage events.[368]

E32.5 Trustpower Limited (**Trustpower**) stated that there is anecdotal evidence of voltage instability issues in Northland arising from a major energy user.[369]

E32.6 WEL submitted that Transpower should consider how the known steady-state overvoltage issues can be managed following the commissioning of further dynamic and static reactive plant. WEL also suggested that Transpower consider the benefits of synchronous condensers in terms of future inertia and fault level contribution.[370]

E32.7 ABB Limited (**ABB**) provided some additional information modelling voltage sensitive loads and how SVCs or STATCOMs need to operate to manage excursions in voltage.[371] Transpower undertook to investigate ABB's response.[372]

E32.8 Golden Bay Cement (**GBC**), a major user of the transmission network, submitted that stable voltage supply was important for its business. Small voltage fluctuations can affect GBC's processes and therefore costs. GBC cited 29 process interruptions due to voltage fluctuations over the past eight years. GBC would support any investment in the transmission network that will result in a more stable supply being available in the Upper North Island provided that any costs passed on to the end consumer were reasonable in comparison to the potential benefits of stable supply.[373]

**Handling of significant market commitments during the Project**

E33 In the short-list consultation, Transpower also consulted on its proposed approach to handling any significant market commitments during the Project. This covered the following matters:[374]

E33.1 the short-list consultation proceeded on the basis of Genesis retiring the Rankines by the end of 2022, without replacement;

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368 Vector, above n 214, at para 11.

369 Trustpower, *Trustpower submission: Waikato and Upper North Island Voltage Management investigation*, 19 July 2019, at pg. 2.

370 WEL, above n 332, at pg. 1.

371 ABB, *Re: Waikato and Upper North Island Voltage Management Consultation*, 22 July 2019, at pg. 1.

372 MCP stakeholder consultation summary, above n 259, at para 4.1.

373 GBC, *Waikato and Upper North Island Voltage Management Investigation Consultation on Short List of Investment Options*, 5 July 2019, at pg. 1.

374 Short-list consultation document, above n 50, at pgs. 28-29.

E33.2 any new generation south of Huntly would not significantly help to meet the voltage stability investment need, but generation at Huntly or north would. To significantly alter the quantum of the need, generation would need to be enough to compensate for the loss of the remaining 500 MW from the Rankines and be operable at winter peaks irrespective of the hydrological situation;

E33.3 Genesis announced in February 2018 that it will stop using coal to generate electricity except in exceptional circumstances by 2025 and it will stop using coal entirely by 2030. This is not a commitment to retaining the Rankines past 2022, but could mean that Genesis extends the Rankines' lives as coal plant until 2025, and as gas plant for normal market operations beyond that date; and

E33.4 if a significant generation commitment – whether to Rankine life extension or to new generation – was made then Transpower would either amend its MCP or, if necessary, seek an amendment to the approved project to reflect its revised preferred option.

E34 The following affected parties submitted on Transpower's proposed approach summarised above:

E34.1 WEL and Counties Power supported Transpower's approach.

E34.2 Contact also agreed with the approach and submitted that the investment process needed to proceed regardless of the Rankine decision in 2022 given that the N-G-1 limit would be breached in 2023 under the P50 level of demand. Contact reiterated its submission on the long-list consultation, stating that it is highly unlikely that any significant new generation will be built north of Huntly due to gas transmission charges.[375]

E34.3 Genesis agreed with the approach and added that the MCP should be structured with a degree of flexibility so that NTSs are prioritised until generation decisions are committed.[376]

E34.4 Meridian supported Transpower's approach and added that "we encourage Transpower to act sooner rather than later to avoid scenarios where the system operator must manage early decommissioning of thermal generation through the tightening of the voltage stability constraint and demand management."[377]

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375 Contact, above n 318, at pg. 2.

376 Genesis, above n 349, at pg. 2.

377 Meridian, above n 367, at pg. 4.

E34.5 Mercury submitted, “we appreciate the uncertainty in both load growth and changes to existing/new generation and therefore believe the proposed approach is appropriate.”[378]

E34.6 Trustpower added that, “Given the uncertainty in the market coupled with the fast-moving technology that has been alluded to in the consultation document, providing Transpower is agile in its response to market commitments, then Trustpower fully supports the proposed approach.”[379]

E35 Submitters accordingly supported Transpower’s proposed approach for managing uncertainties in market generation commitments. Submitters also considered that Transpower should progress the Project but have some flexibility to be able to respond to changes in the generation market.[380]

**Investment options and preferred options**

E36 Transpower considered six investment options. These investment options are set out and discussed in Table D2 above.

E37 The following two components in the investment options attracted particular attention from submitters:

E37.1 the post-fault DMS; and

E37.2 the dynamic reactive support (eg, the DRDs).

*Post-fault DMS*

E38 Certain of the investment options include a post-fault DMS. As outlined above at paragraphs C24 to C26 and C31 to C34 of Attachment C, the post-fault DMS would trip load at selected feeders following particular N-G-1 contingent events. This would reduce the maximum demand to within the voltage stability limits of the next critical event.

E39 As summarised below, interested parties (primarily electricity distribution businesses [**EDBs**]) supported Transpower’s approach to NTSs but raised concerns on the post-fault DMS, which Transpower had originally proposed would trip whole GXPs:[381]

378 Mercury, above n 318, at pg. 2.

379 Trustpower, above n 369, at pg. 2.

380 As noted at paragraph 1.77.2 that in response to submitters’ questions about forecast demand in the WUNI region and the Rankines’ future from the consultation on our draft decision, Transpower expressed willingness in its cross-submission to defer Stage 1 components if, by October 2020, Transpower finds that there is:

(a) no change to Huntly generation until after winter 2023;

(b) a material reduction in peak demand expectation due to Covid-19; or

(c) another material market announcement affecting the investment need of Stage 1.

381 Short-list consultation document, above n 50, at para 5.1.

E39.1 Counties Power[382], TLC,[383] and Vector[384] expressed concern that the post-fault DMS would trip GXPs and that Transpower had not properly assessed the cost of this.

E39.2 Counties suggested that Transpower investigates a scheme like the automatic under-frequency load shedding (**AUFLS**) regime under Technical Code B of Schedule 8.3 of the Code.[385]

E39.3 Vector considered it preferable for all non-critical GXPs to be armed on a rotation basis.[386]

E39.4 WEL commented that entire GXP shedding is a blunt approach that takes no consideration of end customers. WEL considered that EDBs should be able to nominate lower-voltage feeders for load shedding in several priority tranches. This approach would be more equitable between EDBs and reduces the economic cost of load shedding as lower value loads are shed first.[387]

E40 We agree that, to the extent it is feasible and consistent with correct application of the investment test under Schedule D of the Capex IM, Transpower should use NTSs.

E41 Transpower took account of the EDBs' submissions summarised above and modified its design of the post-fault DMS to reflect the major capex project output proposed in the MCP. Transpower advised that its design modifications aim to exclude critical feeders where:

E41.1 feeders have a materially higher value of lost load;[388]

E41.2 excluding the relevant feeders:

E41.2.1 reduces the total cost of the post-fault DMS (including capital and unserved energy costs); and

E41.2.2 does not prevent Transpower having the required quantity and type of load in the post-fault DMS.

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382 Counties Power, *Waikato and Upper North Island Voltage Management Consultation - Short List Options Response - Counties Power*, 19 July 2019, at para 4.

383 TLC, above n 366, at paras 3 to 5.

384 Vector, above n 214, at paras 5-9.

385 The Code's AUFLS regime is designed to trip selected load at GXPs when there is not enough generation to meet demand.

386 Vector, above n 214, at para 6.

387 WEL, above n 332, at pg. 2.

388 The 'value of lost load' in this case is the non-standard value of expected unserved energy equal to $26,500/MWh discussed above at paragraph D30 of Attachment D.

E42 Transpower provided further information on the design features and risk mitigation it proposed for the post-fault DMS.[389] Transpower also committed to working closely with its affected customers to identify the critical feeders to be excluded from the post-fault DMS.[390]

E43 We acknowledge Transpower's engagement with its stakeholders in refining its design and proposed approach to implementing the post-fault DMS. Our views on the post-fault DMS are set out in Attachment C of this paper.

*Emerging dynamic reactive support technology*

E44 ABB submitted that hybrid synchronous condenser technology and hybrid STATCOM technology could provide additional benefits, particularly when system fault levels are reducing due to generation decommissioning.[391] We discuss this option below.

E45 ABB also recommended that Transpower consider STATCOM and hybrid STATCOM solutions (in addition to SVC technology). ABB presented its view of the advantages of these solutions but did not offer to provide them as potential NTS.[392]

E46 Transpower advised that the cost of the hybrid STATCOM is materially higher than that of more established STATCOMs and SVCs. We are also of the view that Transpower should also be cautious introducing devices based on new technology at an early stage of the devices' lifecycle.

**Transpower's consultation on its approach to NTSs**

E47 Transpower consulted with the stakeholders on its approach to considering NTSs. Transpower's specific question was 'do you agree with our approach to NTSs?'. Most stakeholders responded to this question. We summarise several of the responses below.

E47.1 Enel X, a supplier in the demand-side market, supported Transpower's approach to NTSs, stating:[393]

> Yes, it is encouraging to see that demand management solutions are being considered along with traditional voltage support solutions. It is difficult to fully review and comment on the economic assumptions in regard to the demand management solution as the key parameter of expected MWh delivered per annum is not clearly defined. We would also like to note that through our global and local experience in demand response since 2001, in order to have a reliable and firm capacity of a demand management resource participants need to be encouraged with fixed availability payments to justify the business case and focus of participating.

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389 MCP stakeholder consultation summary, above n 259, at para 4.12.2.

390 Above n 259, at para 4.12.1

391 ABB, above n 371, at pgs. 3 and 4.

392 Above n 371, at pgs. 2 and 3.

393 Enel X, *RE: Waikato and Upper North Island Voltage Management consultation*, 22 July 2019, Q5, at pg. 1.

E47.2 Mercury indicated that it is a potential provider of an NTS and would engage with Transpower further on this, stating:[394]

> We note that our grid connected battery and/or generators (as synchronous condensers) could both be expanded to significantly reduce the need/size of a new conventional transmission solution. In the non-transmission solution RFP process, Mercury recommends that Transpower provide more granular information on the dynamic voltage need. Knowing the expected magnitude, frequency, and duration of the dynamic voltage support required will make it easier for potential providers of NTSs to assess whether their solutions are competitive/superior to the SVC approach presented in Option 2.

E47.3 Trustpower questioned whether the proposed investment can be scaled to supplement any NTSs:

> One potential element missing from the analysis is around the NTS and technology, should a market commitment be made, in the form of a new technology solution (either part or complete solution) in the region, is Transpower's preferred solution able to be scaled to appropriately supplement any NTS? Throughout the consultation the major assumption has been that Transpower will provide the whole solution, in reality this may not be the case. If another market participant was to install equipment providing a portion of the solution then Transpower's solutions must be capable of adapting to compliment this in order to deliver the desired outcome. We suggest that some analysis around this point this may be useful.[395]

E47.4 Genesis offered to assess converting the Rankines to provide an NTS under a GSC, stating:[396]

> To minimise the risk of overbuilding, and the consequences that follow, including capital allocation inefficiencies, the procurement of NTSs through Grid Support Contracts (GSC) is essential. We are open to assessing the feasibility and costs of converting a Rankine unit to a synchronous condenser as a potential GSC option.

E48 Submitters considered that Transpower should be able to respond to new NTS technology and consider synchronous condensers. Both ABB and WEL mentioned that Transpower should consider synchronous condensers in its investment mix.

## Second RFI on NTSs

E49 Transpower issued a second RFI on 2 October 2019. In this RFI, Transpower clarified the scope of and performance that would be required from an NTS to meet the investment need.

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394 Mercury, above n 318, at pg. 2.

395 Trustpower, above n 369, at pg. 2.

396 Genesis, above n 349, at pg. 1. We understand from Transpower that Genesis did not respond to the RFI.

E50 In response to the RFI, Mercury provided more technical details and updated costs on the scope to offer the existing plant at Southdown as an NTS.

E51 Transpower advised that it did not receive any further information from Genesis.[397, 398]

[397] Email from Nic Deller (WUNI Project Manager – Transpower) to Hazet Adam (Commerce Commission) on 29 April 2019.

[398] In its cross-submission in our consultation, Transpower has since advised in respect of the second RFI that it received only one response that met the performance requirements and has the potential to economically replace one of the dynamic reactive devices. Transpower confirmed it:

(a) is currently undertaking a formal procurement process for the above NTS option;

(b) expects to receive firm pricing and agree terms for the NTS in September, at which point Transpower will make a final assessment against the Upper North Island DRD; and

(c) following our decision, if it finds that the NTS is the better of the two options under the Capex IM criteria, Transpower will apply to us for a major capex output amendment.

# Attachment F: Acronyms, abbreviations and terms

*Purpose of this attachment*

F1 This attachment lists the acronyms, abbreviations and terms used in this paper in Table F1 below.

**Table F1: Acronyms, abbreviations and terms**

| Abbreviation | Definition |
|---|---|
| 2012 Capex IM reasons paper | Commission's *Transpower Capital Expenditure Input Methodology Reasons Paper*, 31 January 2012 |
| 2017/18 Capex IM review reasons paper | Commission's *Transpower capex input methodology review - Decisions and reasons* paper, 29 March 2018 |
| ABB | ABB Limited |
| Act | Commerce Act 1986 |
| AUFLS | Automatic under-frequency load shedding regime under Technical Code B of Schedule 8.3 of the Code |
| BHL-WKM lines | Brownhill-Whakamaru 1&2 transmission lines |
| BHL-PAK cable | Brownhill-Pakuranga cable |
| Capex IM | *Transpower Capital Expenditure Input Methodology Determination 2012* [2012] NZCC 2 |
| CEO | Chief Executive Officer |
| CIGRE | CIGRE is an international council committed to the collaborative development and sharing of power system expertise |
| Code | Electricity Industry Participation Code 2010 |
| Commission | Commerce Commission |
| Contact | Contact Energy Limited |
| Counties Power | Counties Power Limited |
| Covid-19 | Coronavirus or SARS-CoV-2 disease |
| CUWLP | Transpower's Clutha Upper Waitaki Lines Project |
| Draft decision | Our draft decision of 16 June 2020 to approve Stage 1 |
| DRD | Dynamic reactive device |
| EDBs | Electricity distribution businesses regulated under Part 4 of the Act |
| EDGS | Electricity demand and generation scenarios as published by MBIE in July 2019 at https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-modelling/electricity-demand-and-generation-scenarios/ |
| Enel X | Enel X New Zealand Limited |

| Abbreviation | Definition |
|---|---|
| ETNZ | Energy Trusts of New Zealand Inc. |
| GBC | Golden Bay Cement |
| GEIP | Good electricity industry practice as defined in clause 1.1.5(2) of the Capex IM |
| Genesis | Genesis Energy Limited |
| GFC | Global Financial Crisis of 2008 |
| GRS | Grid reliability standards under Schedule 12.2 of the Code |
| GSC | Transpower's template grid support contract – more information on the GSC is available here: https://www.transpower.co.nz/grid-support-contracts#:~:text=Transpower%20has%20developed%20a%20Grid,transmission%20investment%20under%20certain%20conditions. |
| GXP | Grid exit point |
| IMs | Input methodologies under Part 4 of the Act |
| IPP | *Transpower Individual Price-Quality Path Determination 2020* [2019] NZCC 19 |
| Long-list consultation | Transpower's consultation on its long list of options to meet the investment need of the MCP |
| Long-list consultation document | Transpower's *Waikato and Upper North Island voltage management long-list consultation* document, July 2016 |
| Manapouri | Meridian's Manapouri Power Station |
| MCA | Major capex allowance means the amount of major capex approved by the Commission in relation to a major capex project |
| MCP | Major capex proposal |
| MBIE | Ministry of Business, Innovation and Employment |
| Mercury | Mercury Energy Limited |
| Meridian | Meridian Energy Limited |
| MEUG | The Major Electricity Users Group |
| Mvar | Mega Volt Amps (Reactive) |
| MW | Means megawatt, which is a measure of power |
| MWh | Means megawatt hours and is a measure of energy |
| N-1 criterion of the GRS | The GRS standard at clause 2(2)(b) of Schedule 12.2 of the Code that provides that with all assets that are reasonably expected to be in service, the power system would remain in a satisfactory state following the tripping of one of the transmission assets in the core grid |
| Northpower | Northpower Limited |
| NPV | Net present value |
| NTS | Non-transmission solution |
| NZ Steel | New Zealand Steel Limited |

| Abbreviation | Definition |
|---|---|
| O&M | Operating and maintenance costs |
| OHW | Ohinewai |
| P50 cost estimate | The 50th percentile cost, which means there is 50% probability that Transpower will complete Stage 1 within the P50 cost |
| Part 4 | Part 4 of the Act |
| Post-fault DMS | The post-fault demand management scheme Transpower proposes as a major capex project output for Stage 1 in the MCP |
| PPOs | The system operator's principal performance obligations under clauses 7.2A to 7.2D of the Code |
| Pre-fault DM | Pre-fault demand management that the system operator would carry out under investment option 1 of the short-list consultation document |
| Project | Means the staged major capex project proposed by Transpower in the MCP, and for which Transpower intends to submit a further MCP for Stage 2 when the investment is needed |
| Proposed investment | Means the investment option in the MCP for which Transpower seeks approval |
| Rankines | The two 250 MW-Rankine generation units in active normal service at Huntly Power Station |
| Refining NZ | New Zealand Refining Company Limited |
| RFI | Request for information |
| RMA | Resource Management Act 1991 |
| Short-list consultation | Transpower's consultation on its short list of investment options for the MCP |
| Short-list consultation document | Transpower's *Waikato and Upper North Island voltage management investigation – consultation on short list of investment options* document, June 2019 |
| SPS | A Transpower special protection system |
| Stage 1 | The first staging project (of the Project) to which this MCP relates under the Capex IM |
| Stage 2 | The second staging project of the Project for which Transpower intends to submit an MCP when the investment is needed |
| STATCOM | A static synchronous compensator is a type of electrical plant that provides or absorbs reactive power |
| SVC | A static VAR compensator is a type of electrical plant that is used to provide or absorb reactive power |
| TEES | Transpower's Enterprise Estimation System |
| TLC | The Lines Company Limited |
| Top Energy | Top Energy Limited |
| TPM | Transmission Pricing Methodology under the Code |

| Abbreviation | Definition |
|---|---|
| Transpower | Transpower New Zealand Limited |
| Transpower IMs | *Transpower Input Methodologies Determination 2010* [2012] NZCC 17 |
| TPM | Transmission pricing methodology is the methodology by which Transpower prices its transmission services developed in accordance with subpart 4 of Part 12 of the Code and specified in Schedule 12.4 of the Code |
| Trustpower | Trustpower Limited |
| TWh | Terawatt hours |
| WACC | The weighted average cost of capital we set for EDBs and Transpower in our recent cost of capital determination: *Cost of capital determination for electricity distribution businesses' 2020- 2025 default price-quality paths and Transpower New Zealand Limited's 2020-2025 individual price-quality path* [2019] NZCC 12 (25 September 2019) |
| WEL | WEL Networks Limited |
| WUNI region | Waikato and Upper North Island region |
| WUNIVM | Waikato and Upper North Island Voltage Management |
| Vector | Vector Limited |