TRANSPOWER

Upper South Island Upgrade Project: Summary of short-list consultation submissions and responses

July 2025

Executive summary

This document provides a summary of submissions received on Transpower's *Upper South Island Upgrade: Short-list Project update and consultation* of April 2025 (the consultation paper).[1] We are investigating investments in electricity infrastructure for the upper South Island (USI), north of Twizel, to ensure a reliable power supply for the future. As the region grows and more homes and businesses transition to electricity, it is essential to strengthen the grid to meet increasing demand. The USI region relies heavily on electricity transmitted from the Waitaki Valley due to limited local generation capacity.

We received four submissions from stakeholders, including electricity distributors and major consumers. We appreciate the time and effort invested by all submitters in reviewing our consultation material and providing valuable feedback. In this document we have summarised the key points raised by submitters. For more comprehensive information, please refer to the submissions. We have also provided a response to the submissions, where appropriate.

Overall, most submitters support our preferred option but raise concerns regarding the application of the Transmission Pricing Methodology (TPM) on this project. Orion acknowledges that grid reinforcement in the USI will eventually be required to enable New Zealand's energy transition but raised a variety of issues that we respond to below. We have engaged directly with Orion over its concerns. Having addressed these, we understand that Orion now supports our investment proposal.

Following this consultation, and two earlier consultations, we will further develop our proposal and submit it to the Commerce Commission later in 2025 for approval to invest in our preferred option:

- Constructing two switching stations near Orari and Rangitata
- Upgrading the Orari–Rangitata and the Norwood–Rangitata circuits
- Installing voltage management equipment

Please contact us at usi@transpower.co.nz if you have any questions, feedback, or if you are interested in hearing more about this work.

[1] The consultation, the submissions and this document are available at Further consultation on our short-list for upper South Island upgrades | Transpower.

Submissions received

This section provides a summary of each submission. We thank submitters for their submissions and welcome the opportunity to incorporate the feedback into our Upper South Island Upgrade Project.

Submissions were received from:

- NZ Steel – a major consumer of electricity
- Major Electricity Users' Group (MEUG) – a trade association representing large electricity consumers in New Zealand
- Electricity Ashburton (EA Networks) – an electricity distributor in Canterbury
- Orion – an electricity distributor in Canterbury.

NZ Steel submission

NZ Steel is particularly interested in the application of the TPM and impact on demand customers. It emphasises the need for thorough justification of transmission price increases for consumers remote from the upgrade area. NZ Steel requests that Transpower fully explore and justify the modelled outcomes for supposed demand beneficiaries before proceeding.

Transpower response:
We held a meeting with NZ Steel to discuss the application of the price-quantity method to calculate the TPM allocation for the USI investments, and why it resulted in the modelled outcomes. We also provided some follow-up materials to support this justification. This material will be uploaded to our website shortly.[2]

MEUG submission

MEUG supports the need for the project but has a concern with the indicative starting allocations and benefit-based charges for this project and would like better transparency around how these charges are being forecast. It supported the further consultation process given the substantial cost increase.

MEUG not only supports the need for the project but also supports Transpower seeking a non-transmission solution (NTS) allowance, which could possibly replace or defer the need for investment and welcomes a similar approach to that proposed for the Western Bay of Plenty project.

Transpower response:
We held a meeting with MEUG to discuss the application of the price-quantity method to calculate the TPM allocation for the USI investments, and why it resulted in the modelled outcomes. We also provided some follow-up materials[2] *to help this justification. We are pleased that MEUG is supportive of the NTS allowance approach.*

[2] About the TPM | Transpower.

EA Networks submission

EA Networks supports our preferred option and would like the project to advance as soon as possible. It raised some risks with using non-transmission solutions (NTS) to defer the USI upgrades, such as widespread outages or not addressing the constraint as expected. It also believes global market pressures from electrification will likely drive cost escalation, eroding any potential savings from delaying the project.

EA Networks is concerned about the significant shift in TPM allocation to load customers, specifically that:

- the TPM allocation remains locked regardless of how load growth actually pans out
- our load growth assumption may already be dated e.g., Cook Strait ferry electrification is no longer progressing
- it asks that Transpower revisit its forecasts to take account of a range of likely outcomes.

Transpower response:
Please note that we will consult on proposed starting allocations separately following Commerce Commission approval. The allocations in the short-list consultation are estimates only. When we consult on the proposed starting allocations, and when we issue our decision on starting allocations, we will advise any material changes to assumptions used for the modelling.

Orion submission

Orion acknowledges that grid reinforcement in the USI will eventually be necessary. However, it believes that a more balanced approach to forecasting, which treats generation and demand forecasts uncertainty with equal scrutiny, might reveal that constraints will emerge later than currently projected. This deferral could reduce immediate financial impacts on consumers and allow time for more cost-effective non-transmission solutions (NTS) to be evaluated and implemented. Therefore, Orion recommends that Transpower:

a. conducts a comprehensive review of both load and generation forecasts and assumptions, applying consistent evaluation criteria to both
b. reopens the NTS process
c. provides a transparent analysis of the number of existing and new clearance violations
d. extends the consultation period and facilitates dedicated workshops with affected stakeholders to explore viable alternatives to the current upgrade proposal.

Transpower response:
We have discussed with Orion its concerns and have considered if there is sufficient certainty regarding new generation or reduced demand to defer the need for this project. Following this review we have concluded that while there are several new generation projects in various stages of development, there is very limited certainty about the contribution these could make to peak demand (e.g. a solar project without battery energy storage systems (BESS) will be unable to provide capacity on a winter night).

Talking with larger South Island distribution networks and Fonterra, we have reviewed our demand projections. In summary, while some short-term growth may have been deferred there are still strong expectations of growth in the region. Following our discussions with Orion we understand that it is now supportive of this investment proceeding.

Responses to the four high-level recommendations are below, with more detailed responses to Orion's comments in Table 1.

a. *Our approach prudently assumes demand growth without relying on uncommitted generation. This was consulted on in December 2024, with no objections, and remained materially unchanged in the more recent consultation. We acknowledge that assuming more generation in the USI would likely reduce benefits from transmission investment and may have some impact on benefit-based investment allocations. We will incorporate updated generation information as sensitivities in our Investment Test. We plan to consult on allocations following the approval of this project. At that time, we plan to consider further the treatment of new generation on the resulting allocations.*

b. *We plan to seek an NTS allowance based on the full project deferral value, consistent with our Western Bay of Plenty MCP. This ensures approved funding to contract and defer the project if a viable NTS is available. Engagement with NTS proponents will commence in parallel with our Commerce Commission approval. If an economic NTS is identified that can defer the need for the transmission investment, we will reassess the required timing for the transmission solution. We also carried out an RFP process seeking NTS options, which closed in April 2024.*

c. *We have identified 96 spans with existing clearance violations (prior to the TTU) and 218 spans with clearance violations (including both new violations and those made worse) after the TTU. The Proposal will include a proposed framework for allocating the costs of remedying these issues, including the costs that would be covered by this MCP.*

d. *Given that this investment is in the core grid and the support from other stakeholders to proceed, we propose to continue with our planned application to the Commerce Commission. We have engaged directly with Orion to address their concerns and ensure they are included in our NTS process. We are also observing increasing lead times for critical equipment from international suppliers that reinforces the need for early commitment to procurement to manage delivery risks and maintain realistic project timeframes to meet our need dates.*

Table 1: Detailed response to Orion's submission

Paragraph in Orion's submission	Submission topic	Transpower's response
4	A 200 MW South Island peak demand reduction in Transpower's Security of Supply Assessment 2025 has not been reflected in the USI investment case.	The Security of Supply Assessment forecast is for a different purpose and as such has different scenario assumptions. The change in the Annual Assessment H100 peak forecast (which differs from the actual peak) between 2024 and 2025 is primarily driven by the change in notification of steps loads from customers. In particular the 2024 Annual Assessment forecast included, in the USI, over 65 MW of steps occurring in 2025 that were then omitted, delayed or reduced in the 2025 Annual Assessment forecast. None of these steps were included in the initial forecast for the short list consultation, and the reduction of the Annual Assessment forecast from 2024 to 2025 is not the same as a reduction from the Shortlist forecast of USI. Nevertheless, we have assessed if updated demand information relating to the Upper South Island would significantly impact the need for this project. Our view is that a complete update of all inputs to the forecast would not materially change the conclusions presented here.
5a	Uncertainty of Fonterra dairy factory electrification.	In their February 2025 submission Fonterra submitted that it was prudent for us to continue to plan for the electrification of Clandeboye, Darfield and Studholme. While there is currently an investment in biomass boilers some industrial processes at Clandeboye are assumed to electrify between 2025 and 2031 based on advice from Fonterra. These do not represent full electrification of the site. Our understanding is that they remain reasonable (and potentially low). Currently, Studholme is supplied via Timaru in summer periods to manage supply to Oamaru, and from Waitaki in winter months. As the need date for investment is also driven by winter constraints, investment would still be needed to alleviate the USI winter constraint.

5a, footnote 5	Resolving constraint in the LSI & summer switching at Studholme.	The load at Studholme is forecast to reach 13.7 MW by 2028, increasing to 16.2 MW by 2050. While this represents a moderate increase, it remains relatively small compared to the Upper South Island (USI) load and offers limited benefit in alleviating USI load constraints. The lower Waitaki area is already experiencing several interrelated network issues (outlined below). Supplying Studholme from Waitaki would worsen these problems. **1. <u>TPR 2023 (18.4.1.1) – Summer Peaking and Operational Constraints</u>** The Oamaru, Black Point, Bells Pond, and Studholme grid exit points all peak during summer, when circuit ratings are lower. While it is technically possible to transfer Studholme's supply to Waitaki during summer, this requires manual switching by an on-site operator. Such transfer would worsen existing 110 kV transmission constraints from Waitaki to Oamaru. **2. <u>TPR 2023 18.4.1.2 – Thermal Overloading Risks</u>** Thermal overloading risks exist on the two 110 kV circuits from Waitaki to Bells Pond and Black Point during summer: • The Bells Pond–Waitaki circuit may overload following an outage of the Oamaru–Black Point–Waitaki-1 circuit (from around 2023). • The Black Point–Waitaki section may overload following an outage of the Oamaru–Studholme–Bells Pond–Waitaki-2 circuit (also from around 2023). In the medium term, all feasible options to extract additional capacity from the existing grid assets are expected to be exhausted. **3. <u>TPR 2023 18.4.1.3 – Oamaru Load Growth</u>** The Oamaru load may exceed the N-1 thermal capacity of the two 110 kV Glenavy–Oamaru circuit sections, posing a risk to supply reliability. **4. <u>TPR 2023 18.4.1.4 – Reverse Power Flow and Voltage Stability</u>** The loss of transformer WTK-T24 results in the 110 kV Oamaru–Black Point–Waitaki circuit being back-fed through the Oamaru T1 transformer. Reverse power flow protection would typically disconnect Oamaru-T1, leading to a loss of supply at Black Point. If Oamaru-T1 remains connected, it could cause voltage collapse at both Black Point and Oamaru, and low voltages at Bells Pond. Similarly, the loss of Waitaki-T23 causes the Oamaru–Studholme–Bells Pond–Waitaki circuit to be supplied via reverse power through Oamaru T2. This could result in a loss of supply at Bells Pond and Studholme (in winter), or voltage collapse at Bells Pond and Oamaru, with low voltages at Black Point.

5b	Uncertainty of Cook Strait ferry electrification.	We agree that discussions regarding the electrification of the ferry have progressed since we first released our consultation material. In our analysis we assumed an 8 MW step load in 2025. The removal of this step load has a small impact on the demand forecasts and will not materially affect the need date.
5c	Uncertainty of electrification caused by RETA reports.	We recognise the uncommitted nature of the projects identified in the RETA studies. In our forecasts we have attempted to capture the potential and likely impact future electrification will have on demand growth consistent with the EDGS scenario variations we are using for this project. If we ignored this potential growth, we believe we could significantly underestimate potential demand growth in the region. To derive our forecasts for electrification we have drawn on what information is available. We consider the RETA studies to be a useful resource to inform this growth. The RETA steps we have included in the scenarios (excluding Fonterra's Darfield plant) amount to 25 MW in 2033 and 5 MW in 2036. As mentioned above, the advice from Fonterra is that it would be prudent to plan for the electrification of its Darfield plant.
5d	Uncertainty of Christchurch International Airport (CIAL)'s load growth.	CIAL responded to our Long-list consultation suggesting that our forecasts did not appear to allow for the electrification of aviation. After some consideration we decided to add two 5 MW steps in 2030 to account for the potential for EV aviation charging. We decided to not include the potential for hydrogen production due to it being uncertain, and due to an expectation that it would avoid production at peak times. No step load information provided to us by Orion indicated allowance for this additional growth. We have included the 150 MW Kowhai Park solar generation in our analysis. We believe our assumptions are reasonable and appropriate for infrastructure planning.
5e	Tiwai demand response contract.	Following announcements in May 2024 we have revised our assumptions regarding the continued operation of the Tiwai Aluminium Smelter. In our analysis we have modelled it as continuing to operate. We have not modelled Tiwai's demand response contract as we are not privy to when it will be called in the future as we understand that is at the discretion of Meridian. As the focus of this investigation is on supply to the Upper South Island, we do not consider assumptions about Tiwai's demand response contract are material to the analysis.

6, 7	Inconsistent treatment of generation and load.	In our analysis of the need for the project we considered scenarios where demand continues to grow through a range of factors, such as known new step loads and electrification, but new uncommitted generation is not built. This was to adopt a prudent approach and to avoid placing reliance on uncommitted and uncertain new generation to resolve transmission constraints. We used a similar approach in our benefit analysis. We consulted on this approach in December 2024 and received no feedback. We recognise that assuming more generation and/or new large BESS in the Upper South Island would likely reduce the benefits from transmission investment. However, as new generation and BESS are unlikely to affect the order of the options in the application of the Investment Test, and investment is required to meet the deterministic limb of the Grid Reliability Standards such that a positive net benefit is not required, we consider this is unlikely to alter the conclusions of the Investment Test. To test this view we have undertaken a number of sensitivities that have a variety of assumptions about new generation.
8, 9	Updated generation information	There are a number of potential new generation plants in the USI but it is difficult to assess their certainty. To explore how the results may change with different levels of new generation we have considered four new generation sensitivities in our Investment Test. They assume the following additional generation capacity in the Upper South Island (over our base assumptions). • Sensitivity 1: Around 200 MW solar and 100 MW BESS • Sensitivity 2: Around 300 MW solar and 150 MW BESS • Sensitivity 3: Around 300 MW solar • Sensitivity 4: Around 300 MW solar, 150 MW BESS and 300 MW wind.
11a	The number of clearance violations that are currently in breach of NZECP 34, prior to any investment.	We have identified 97 existing violations (96 irrigator + 1 ground clearance) on 96 spans, prior to any investment.

11b	The number of clearance violations that will be caused by an upgrade of both the Norwood – Rangitata and Orari – Rangitata circuits to 90°C.	We have identified the following violations for each circuit. • Norwood – Rangitata: 207 spans with violations (195 ground clearance violations and 130 irrigator violations at these spans) • Orari – Rangitata: 7 spans with violations (2 ground clearance violations and 7 irrigator violations at these spans).
11c	The number of clearance violations that will be caused by the planned upgrade to the Orari – Rangitata circuit to 100°C.	We have identified 11 spans with violations (9 ground clearance violations and 8 irrigator violations at these spans), i.e. eight additional violations going from 90°C to 100°C.
12	Confirmation that the upgrade costs for the investment will only address the net increase in clearance issues resulting from the thermal rating changes, rather than remediating pre-existing compliance issues.	Transpower agrees with the principle that only violations caused by the project should be funded through this MCP, and that the existing violations should be funded by alternative means. We have developed a framework to allocate the costs where they should ideally sit. This framework allocates costs to fix existing violations to either Base Capex or to landowners, dependant on the nature of the violation. We will include a more detailed framework to address this issue in the costing attachment of our proposal.

13	Justification for increasing Orari-Rangitata circuit to 100°C requires a clearer explanation.	In our first shortlist consultation, we proposed to upgrade Orari-Rangitata to 90°C. We expect the thermal upgrade cost to 100°C to be around $1.3M higher than 90°C (to resolve eight additional violations). This will provide 50% additional increase in capacity (90°C gives an additional 256 Amps, 100°C gives an additional 381Amps). The original development plan also indicates that we need additional capacity in the foreseeable future i.e., reconductoring of the same circuit in 2035. With the 100°C thermal upgrade, this reconductoring is no longer needed until after 2050 and therefore defers approximately $4.6M from 2035 to 2053 (note, as this investment is now beyond the analysis horizon of 2050, the cost has been removed). With 90°C and NTS, we believe that it would only delay the need to reconductor the line in 2035 by a couple of years.
15	Whether the additional line turn-in costs may alter the evaluation of NTS.	The increase in cost does not affect the NTS call profile communicated in our NTS RFP. It increases the amount of funding for NTS that we intend to include in our investment proposal.
17	Orion questions why Transpower closed the NTS process rather than maintaining an open call throughout the MCP development period.	The RFP responses showed limited existing NTS capacity and difficulty in defining pricing and other contractual terms. We plan to seek an NTS allowance based on the full project deferral value, consistent with our Western Bay of Plenty MCP. This funding would allow NTS options that arise post approval of this MCP.
19-24	Inadequate evaluation of alternative solutions - Orion recommends that Transpower further evaluate whether a hybrid approach, combining modest thermal rating upgrades with the implementation of non-traditional solutions (BESS) or otherwise might offer a	We plan to seek an NTS allowance based on the full project deferral value, consistent with our Western Bay of Plenty MCP. This ensures approved funding to contract and defer the project if a viable NTS is available. Engagement with NTS proponents will commence in parallel with our Commerce Commission approval. If an economic NTS (including BESS) is identified that can defer the need for the transmission investment, we will reassess the required timing for the transmission solution.

	more cost-effective approach – especially in scenarios where opportunities for value-stacking exist.	
25-27	Timeline concerns	Given that this investment is in the core grid and the support from other stakeholders to proceed, we propose to continue with our planned application to the Commerce Commission. We have engaged directly with Orion to address their concerns and will ensure they are included in our NTS process. We are also observing increasing lead times for critical equipment from international suppliers. This reinforces the need for early commitment to procurement to manage delivery risks and maintain realistic project timeframes to meet our need dates.
30	Customer cost implications – asymmetry in generation & load forecasting.	We do recognise that assumptions about new generation may have some impact on benefit-based investment allocations. We plan to consult on allocations following the approval of this project. At that time, we plan to consider further the treatment of new generation on the resulting allocations.

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