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Management response to the conclusions from the Te Kanapu high level cost estimation models review

Background

Through our Te Kanapu initiative, Transpower is building a future grid blueprint for Aotearoa New Zealand to guide investments in the grid up to and beyond 2050, supporting the country's future economic growth and net-zero aspirations. The transmission options workstream has identified options available to feasibly increase the capacity of our transmission network, maximise existing capacity, or how new and emerging technologies can be used to achieve a similar outcome.

As part of this workstream, five cost estimation models were developed to provide high-level indicative cost estimates for key transmission assets: substation, cable, HVDC station, line upgrade and new line. A Basis of Estimate (BOE) was also developed to give context and outline the principles used to develop the models.

These models were not designed for detailed project costing or investment tests, but to support early-stage option screening to help inform the long-term grid blueprint. They are positioned as Class 5 screening-level estimates, based on the AACE International estimate classifications, which defines five classes of cost estimates based on project definition maturity, ranging from concept screening (Class 5) to final bid (Class 1) with lower class numbers indicating higher maturity and accuracy.

Scope

Mott MacDonald was engaged as an independent expert to review the models, and make recommendations to help strengthen them, across three phases.

Phase 1 and Phase 2 focused on reviewing the models themselves. Phase 1 holistically reviewed the model structure, logic, usability, and transparency. Phase 2 reviewed in more detail the underlying cost components within the models for completeness and alignment with international benchmarks. The Phase 3 scope was more refined focusing on how targeted improvements around escalation frameworks and technology selection could support long-term planning under uncertainty.

Conclusion

In Phase 1 Mott MacDonald summarised that, if interpreted at Class 5, the models provide useful high-level directional insight for option screening, and Phase 2 reiterated that the result of Transpower's work can be construed as a fit-for-purpose Class 5 model. Phase 2 included component-level recommendations across all five asset models against international benchmarks.

In Phase 3, Mott MacDonald provides insights on how Transpower's ability to deliver an affordable, resilient future grid will depend less on predicting the 'right' technology today, and more on sequencing decisions in a way that preserves flexibility, manages escalation risk, and allows the system to evolve as uncertainty resolves over time.

Overall Mott MacDonald concludes that, taken together, the BOE and models form a structured Class 5 screening platform, appropriate for concept selection and option ranking. The models provide useful directional insight at an order-of-magnitude level and cover the core asset classes required for Future Grid planning.

Mott MacDonald concluded that there are several elements within the BOE and models which imply or exhibit characteristics closer to Class 3 or 4 estimates. Therefore a key risk was raised that, if shared more widely, they could be mistakenly interpreted and applied at a higher level of cost estimation class creating material regulatory, financial and reputational exposure. Several strengths and weaknesses were also identified from the reviews, and our response to the identified areas of improvement is summarised below.

Transpower response
To manage misapplication risk, any model outputs or summary material shared internally or externally will clearly state that the estimates are AACE Class 5 screening-level estimates for long-term option screening only. A decision on wider model release will be made separately, considering the risk that the detailed estimate structure may be interpreted as implying a higher level of maturity.

Whilst several areas for improvement were identified across the phases of work, the intention of these models is to provide high-level Class 5 screening-level estimates. At this stage in Te Kanapu, we are comfortable that we have achieved this and do not intend on implementing changes to achieve higher levels of project maturity or accuracy.

However, we have used the findings to improve how the models are applied and communicated. The international benchmarks for component level costs were used to update our estimates in areas where we have limited experience (e.g. 400kV substations, HVDC). We are also taking a more flexible approach to planning so decisions can adapt as technologies, costs, and system needs evolve.

Key weaknesses identified are summarised below, with the actions taken to address these:

Summary of weakness identified	Actions taken by Te Kanapu team
Inconsistent escalation treatment across models	Adoption of the Three Horizon Escalation Framework recommended in Phase 3, which provides a structured way to consider how costs may change in the short, medium, and long term as the energy system evolves.

Overheads and risk allowances that appear arbitrary and insufficiently evidenced	Overhead and risk allowances are based on Transpower project data. The BOE was subsequently updated to clearly reference the basis for each overhead and risk allowance.
Limited treatment of property and consenting risks	Development of a property cost model by combining Quotable Value (QV) land valuation and area data with calculations of easement areas affected by new or upgraded transmission.
A lack of integration across the models to form a coherent system-level view	Development of a central model that references the asset specific models. This enables the combination of models into one cost estimate.

To view the full reports refer to:

- Phase 1 – Holistic review of cost estimation models
- Phase 2 – Review of cost model components
- Phase 3 – Main report
- Phase 3 – Technology report
- Phase 3 – Three Horizon Adoption and Escalation Framework

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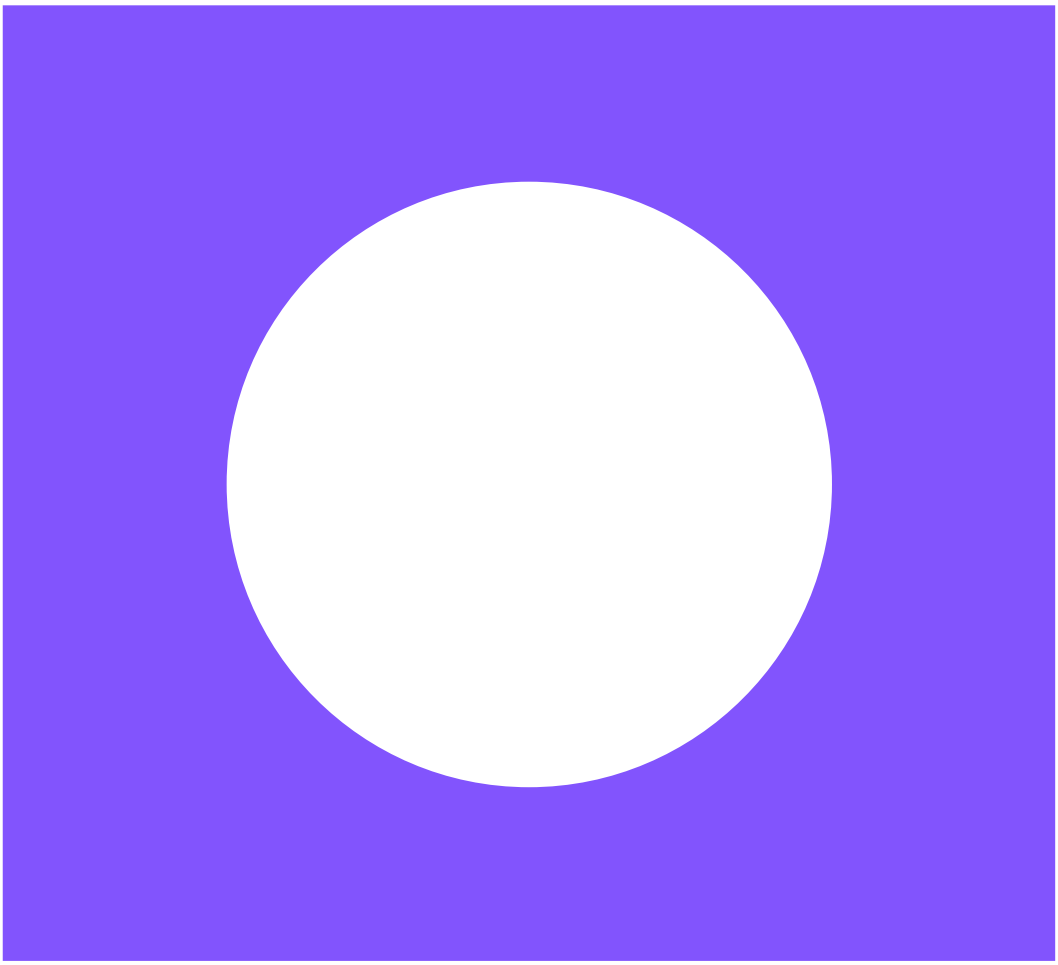
MOTT MACDONALD



Transpower - High Level Cost Estimation Models Review

Phase 1 - Holistic Review of Cost Estimation Models

11/03/2026

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Transpower - High Level Cost Estimation Models Review

Phase 1 - Holistic Review of Cost Estimation Models

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Contents

Review Inputs 3

Introduction 4

1 Executive Summary 5

2 Glossary (Selected Terms) 6

3 Methodology of Review 7

4 Cost Estimation Models Holistic Review 8

4.1 Coverage 8
4.2 Logic 8
4.3 Strategic Fitness 8
4.4 Adoptability 9
4.5 Usability 9

5 Review Summary 10

5.1 Strengths 10
5.2 Weaknesses 10
5.3 Misapplication Risk 10

6 Conclusions 11

6.1 Strengths Observed 11
6.2 Critical Weaknesses 11

A. Comparison Table 12

B. Transpower Review Comments 14

C. Clarifications and Content 15

Review Inputs

File Name	Description
Basis of Estimate - Future Grid (V1)	Basis of Estimate
20250715_New_Substation_Cost_Model_Draft	New Substation Cost Model
20250730_New_Cable_Cost_Model_Draft	New Cable Cost Model
20250811_New_HVDCStation_Cost_Model_Draft	New HVDC Cost Model
20250820_Line_Upgrade_Cost_Model_Draft	Line Upgrade Cost Model
20250820_New_Line_Cost_Model_Draft	New Line Cost Model

* Please refer to section 3 for other input documents considered in this review

Introduction

Transpower's Te Kanapu (Future Grid) initiative represents a bold and necessary vision for New Zealand's transmission system future. The Future Grid programme is a strategic initiative aimed at coordinated long-term planning, focusing on long-term investments such as new lines.

We fully appreciate the importance of developing streamlined, consistent, and user-friendly cost models to support preliminary planning decisions for the network of the future shaped by decarbonisation, electrification, resilience, and distributed generation.

We also understand Transpower's requirement to have 'overnight' capital costs as the primary outputs from the cost models, while additionally identifying escalation drivers to future-proof strategic modelling as needs evolve.

Transpower has provided five separate Excel cost models for review as follows:

- New AC transmission lines;
- New DC links;
- New AC substations;
- New underground and subsea cables; and
- Upgrade of an existing line.

A Basis of Estimate has been prepared by Transpower to give context and outline the principals used to develop the models, which we have similarly reviewed.

This report presents Phase 1 of this assignment, which provides a holistic review of the cost models including: logic, usability, and transparency, and providing commentary on escalation risks and opportunities for refinement. Phase 2 involves review of the component costs within the models and this will be presented in a separate report.

1 Executive Summary

Mott MacDonald has undertaken a review of Transpower's Basis of Estimate (BOE) along with a suite of five cost estimation models for various elements of the New Zealand transmission system (substation, cable, HVDC station, line upgrade, and new line). These models are intended to provide high-level costing to support preliminary optioneering as part of the Future Grid programme. That is, the cost models will help inform the future blueprint but are not intended to be used for the Grid Investment Test (GIT).

Transpower has positioned the Future Grid BOE and associated models as Class 5 screening-level estimates. However, our review found that several elements within both the BOE and supporting models imply or exhibit characteristics closer to Class 3 estimates. These include the level of breakdown in cost categories, the inclusion of validation exercises, and the structured work-breakdown style presentation. This inconsistency between the labelled estimate class and the methodology applied may risk creating a degree of ambiguity in interpretation.

Our Phase 1 holistic review interrogated all models and the governing BOE to identify major strengths and areas requiring further development.

Strengths include:

- Transparency of cost breakdown and structure.
- Inclusion of validation exercises that attempt to benchmark against actual project data.
- The use of logical frameworks that allow consistent application across asset types.

Key weaknesses identified include:

- Inconsistent escalation treatment across models.
- Overheads and risk allowances that appear arbitrary and insufficiently evidenced.
- Limited treatment of property and consenting risks.
- A lack of integration across the models to form a coherent system-level view.

Validation exercises indicated variance ranges of –31% to +57%, which can be considered broadly within the tolerance of a Class 5 estimate.

A key risk is therefore not that the models are inherently incorrect, but that they risk misapplication. If interpreted as Class 5, they provide useful high-level directional insight for option screening. However, if the Class 3 characteristics are mistakenly applied, as the BOE and models sometimes imply, they risk creating material regulatory, financial, and reputational exposure. This is especially important considering the intention to share the models with the wider industry.

2 Glossary (Selected Terms)

Term	Definition (as used in this report)
BOE	Transpower Basis of Estimate (V1)
Injurious affection	Compensation for loss of value/amenity to land from works (e.g., easements, access constraints) without full acquisition.
TEES	Transpower Enterprise Estimating System; historic unit rates database.
AACE Class 3	Estimate with –20%/+30% accuracy expectation under defined design maturity.
AACE Class 5	Estimate with –50%/+100% accuracy expectation under defined design maturity.
TTU	Tactical Thermal Upgrade: minor works to raise rating without major rebuilds.
P50 / P90	Probabilistic cost points at 50% / 90% confidence levels.

3 Methodology of Review

To present robust artefacts for Phase 1 of the project, both the BOE and Cost Models have been reviewed holistically considering five key evaluation questions aligned with Transpower's stated objectives:

- **Coverage** – Do the five cost estimation models cover the range potential options for transmission investment?
- **Logic** – Does the chain of logic that is used within each model make sense?
- **Strategic fitness** – Are the cost estimation models fit for purpose to inform high-level strategic direction for investment?
- **Wider adoption** – Are the cost estimation models sufficiently easy to use such that they would they be useful to the wider industry?
- **Usability** – Can the models be easily understood by a suitably experienced person?

Our assessment combines qualitative analysis - clarity, structure, transparency - with quantitative review including variance analysis, escalation treatment, and benchmarking against actual project data. We have drawn on industry sources including AACE RPs (17R-97, 18R-97, 34R-05, 40R-08) and relevant standards (IEC 60071, AS/NZS 7000, AS 2067).

The BOE and each model was reviewed for coverage, logic, strategic fitness, usability, and adoptability. We compared key quantities and unit rates with Mott MacDonald benchmarks, Rawlinsons 2024, CIGRÉ TBs, AEMO ISP datasets, and recent NZ/AU transmission projects. We tested escalation and risk treatment via simple scenarios and constructed worked examples where model logic is unclear.

Particular emphasis has been placed on determining not only the accuracy of the models, but also the appropriate class designation, risk treatment and constructability realism* in their current form.

A more detailed analysis of each of the models will be provided in the Phase 2 Report.

**Constructability Realism* - *in today's market this is of real concern when strategically costing and planning projects. It has been our experience that this is the area that has notably negatively impacted major infrastructure projects both economically and socially across local communities.*

4 Cost Estimation Models Holistic Review

4.1 Coverage

The five cost models (Transmission Line – new build, AC Substations, New Cable, Line Upgrade (TTU and re-conductoring/duplexing), and HVDC Stations) collectively span the major transmission asset classes for both greenfield and brownfield contexts.

Configurations include bus arrangements and bay counts for substations, overhead line typologies and voltage classes, underground/submarine cable systems, and station-level elements for HVDC. This breadth is appropriate for concept identification and option screening across the Future Grid blueprint.

When compared with recent NZ transmission projects and international practice, several secondary but cost-significant drivers are either omitted or treated superficially: outage and access management, brownfield enabling works, consents and property, environmental/social factors, commissioning/decommissioning, O&M allowances, and system integration requirements.

Conclusion: Coverage is adequate for Class 5 concept screening however anything beyond that will require explicit inclusion of secondary factors.

4.2 Logic

All models follow a consistent WBS-style flow of Inputs → Quantities → Component unit costs (largely TEES-derived) → Overheads (design, Transpower OH, contractor OH) → Risk allowance → Property → Escalation → Roll-up.

For example the logic flows are: substation quantities are derived from bus configuration and bay counts; line and cable models convert route length to circuit-km and apply structure/jointing assumptions; TTU uses TART/TARF-type logic; HVDC is a station-level assembly with AC interface drawn from the substation model.

Strengths: Transparent structure, common uplift framework, validation tables present.

Weaknesses: Reliance on historic TEES rates, flat escalation, compounding overheads, static risk allowance, generic property costing, and limited treatment brownfield/constructability factors.

Conclusion: The logic needs to be refined to align with the desired output (i.e. Class 5) but is clear and repeatable, however is fragile in model engineering fidelity. Appropriate for Class 5 directional use.

4.3 Strategic Fitness

The BOE positions the cost models as tools to inform high-level strategic investment planning, consistent with AACE Class 5 expectations. The observed variance range of –31% to +57% aligns with typical screening-level tolerances.

These models are therefore fit for purpose as optioneering instruments (only) - supporting concept selection, scenario comparisons, and order-of-magnitude assessments. They should not be treated as suitable to provide inputs for business-case budgeting, regulatory submissions, or investment-grade decision making (which we understand is not the intent).

Strengths: The models provide broad coverage of major transmission asset classes, i.e., lines, substations, cables, HVDC, upgrades. This is useful for rapid “what-if” testing of span lengths, bay counts, transformer configurations, etc., and enables consistent screening across greenfield and brownfield scenarios.

Weaknesses: Reliance on static unit rates (often historic TEES values) that are not indexed to market conditions**.** Escalation and risk uplift treatments are fixed and compounded and are applied arbitrarily across asset classes. Probabilistic modelling is absent, reliance on single-point P50 outputs introduces false precision. Validation exercises highlight divergence from real project benchmarks.

Conclusion: These models are fit for purpose as optioneering instruments — i.e., for supporting concept selection, scenario comparisons, and order-of-magnitude assessments.

4.4 Adoptability

For a model to be broadly adopted beyond its originator, it must be transparent, benchmarked, governed, and easy to transfer. The current suite is serviceable for internal use but is constrained by structural weaknesses.

Strengths: Framework provides a clear baseline and could evolve into a sector-wide standard if strengthened. Modular design allows incorporation of additional cost drivers (e.g., outage management, consenting).

Weaknesses: Reliance on aged rates and absence of market-indexed inputs. No clear pathway for incorporating brownfield complexities, property/consenting risks, or engineering constraints. Weak governance framework; no independent QA, peer review, or validation cycle.

Conclusion: Low adoptability today, however with some redevelopment - including benchmarking against CIGRE TBs, AEMO ISP assumptions, and recent NZ/AU project data - the models could be elevated fit for sector-wide adoption.

4.5 Usability

The models are delivered in Excel workbooks, with consistent tabsets and transparent formulas, making them accessible to experienced internal users. However, practical usability for external stakeholders and decision-makers is limited.

Strengths: Familiar Excel environment; easy to open, share, and manipulate. Modular structure: separate sheets for quantities, property costs, risk, and escalation. Transparent formula chains (compared to TEES’ black-box outputs).

Weaknesses: Heavy reliance on hard-coded cells and static inputs, which limits sensitivity analysis. Lack of scenario toggles for changing assumptions (e.g., span length, brownfield constraints). Single-point outputs (P50 only) and no stochastic or Monte Carlo risk treatments. Limited QA, governance, and version control — no clear audit trail for changes.

Conclusion: Usable internally for early screening but not adequately robust for non-specialists, regulators, or stakeholders without further development. Governance, version control, and scenario management would need to be hardened.

5 Review Summary

Taken together, the BOE and models form a structured Class 5 screening platform, appropriate for concept selection and option ranking. They provide useful directional insight at an order-of-magnitude level and cover the core asset classes required for Future Grid planning.

5.1 Strengths

- Breadth of coverage including lines, substations, cables, HVDC, and upgrades.
- Consistent workbook structure, supporting rapid optioneering.

5.2 Weaknesses

- Outdated rates, static escalation, compounding uplifts.
- Key gaps include brownfield constraints, consenting risk, O&M, property impacts.
- Minimal probabilistic treatment of uncertainty.

Note that the artefacts that resemble Class 3 in structure such as WBS format, validation tables, benchmarking attempts, should be amended to match the underlying mechanics and data. This mismatch introduces misapplication risk (particularly when through the lens of wider adoptability and usability) as users may misinterpret the models as investment-grade when they are not.

5.3 Misapplication Risk

As an example of where misapplication risk arises:

Section 4.0 Scope & Methodology of the BOE introduces models based on structured asset classes (lines, cables, substations, HVDC) but also incorporates bay-level substation configurations and defined span lengths for transmission lines. These inputs resemble the granularity expected of Class 3 preliminary layouts, whereas a Class 5 model would typically remain at higher-level unit aggregates (e.g., $/km or $/MVA).

Similarly, Section 6.0 Estimate Classification and Validation presents variance ranges of –31% to +57%, which sit within Class 5 tolerances. However, the validation is undertaken in a structured, tabulated format directly comparing model outputs to historical project data. This WBS-style validation framework is a Class 3 characteristic and could be interpreted by non-specialist readers as evidence of budget-level robustness rather than concept-screening only.

The Excel workbooks reinforce the risk of blurred cost Class boundaries. The substation model (July 2025 draft) shows detailed inclusions such as civil works, secondary systems, protection cabinets, and bay-by-bay equipment counts. While useful for transparency, this level of granularity is inconsistent with Class 5 practice.

Taken together, these examples demonstrate how the presentation style (WBS tables, validation charts, structured workbooks) elevates the apparent maturity of the models above their intended Class 5 role. The underlying mechanics — reliance on aged rates, static escalation, and simplified risk allowances — remain aligned with Class 5, but the outward appearance of Class 3 traits creates a misapplication risk if the models are used for regulatory submissions, detailed budgeting, or investment decision-making without further redevelopment.

6 Conclusions

Our independent holistic review of Transpower's Basis of Estimate (BOE) and the five associated cost models (Transmission Line, AC Substations, New Cable, Line Upgrade, and HVDC Stations) has confirmed that the suite of models provides useful directional insight at Class 5 maturity, but it also presents inconsistencies, misclassifications, and structural weaknesses that limit its reliability for anything beyond high-level screening, and suitability for sharing with a wider audience.

6.1 Strengths Observed

- Breadth of coverage: the models capture the main transmission asset classes required for Future Grid optioneering.
- Consistent structure: delivered in Excel with a repeatable tabset (Inputs, Assumptions, Risk/Property, Outputs).
- Validation exercises: benchmarking against recent projects (BHL–PAK, ROX–ISL, etc.) demonstrates willingness to test outputs.
- Rapid scenarizing: models can be adjusted quickly to explore sensitivities around span lengths, conductor types, bay counts, and route lengths.

6.2 Critical Weaknesses

- Estimate classification mismatch/misapplication risk: labelled as Class 5 but presented with Class 3-style mechanics, creating potentially misleading precision.
- Escalation and overheads: inconsistently applied, often flat, risking double counting and undermining realism.
- Risk treatment: reliance on flat uplifts rather than probabilistic or activity-based methods.
- Property and consenting costs treated generically, underestimating risk in urban or environmentally sensitive areas.
- Brownfield constraints: limited treatment of outages, temporary works, and integration.
- Governance and usability gaps: lack of audit trails, version control, and data dictionaries increases risk of corruption or misuse.

A. Comparison Table

The following table summarises various aspects that may be expected to achieve AACE Class 5 costing, compared to what was observed in Transpower's BOE and costing models.

Table 1 Comparison Table

Dimension	AACE Class 5 (Screening)	Transpower BOE/Models
Maturity of Design	0-2% definition, no design drawings, broad assumptions only.	BOE Section 4.0 Scope & Methodology models use structured asset classes (e.g., line, cable, HVDC, substations), and in some cases assume bay-level substation configurations and span lengths. This resembles Class 3-style input structures, not Class 5.
Accuracy Range	50% to +100% variance expected.	BOE Section 5.0 Estimate Classification explicitly claims Class 5 but also cites validation exercises (Section 6.0) showing variance of 31% to +57%. This sits in Class 5 tolerance but is presented in a Class 3-style validation framework.
Structure of Costing	High-level aggregates only (e.g., $/km, $/MVA). Minimal WBS.	Models in Excel (screenshots reviewed) show detailed WBS-style breakdowns e.g., Substation model (screenshots, July 2025 draft) includes civil works, secondary systems, protection cabinets, comms equipment, and bay-by-bay quantities. This level of granularity is inconsistent with Class 5.
Treatment of Risk	Flat uplifts, applied globally (e.g., +25% overhead, +40% property).	BOE Section 9.0 Risk & Confidence Levels uses flat uplifts (25% overheads, 40% property risk), consistent with Class 5. However, the same section also references P50/P90 outputs, a probabilistic artefact more aligned to Class 3, but without the supporting methodology.
Validation	Rare, minimal or anecdotal benchmarking.	BOE Section 6.0 Estimate Review Validation benchmarks against as-built projects (e.g., BHL PAK cable project, ROX ISL line record). Provides variance tables (+31 to -57%). Validation exercises are a Class 3 hallmark, but tolerance bands clearly sit in Class 5.
Escalation	Generic escalation (e.g., single CPI %).	Models apply uniform escalation uplifts (e.g., substation workbook 2025 costs tab). Escalation is applied inconsistently This reflects a hybrid between Class 5 simplicity and Class 3 intent.

Use Case	Strategic screening only, not defensible for regulatory filings.	BOE Executive Summary + Section 1.0 Purpose explicitly state intent is to inform the Future Grid blueprint. However, use of Class 3-style validation artefacts risks misapplication for regulatory/Commerce Commission purposes, introducing reputational and financial exposure.
Governance	QA and version control expected	Transpower's suite of documents have limited QA, versioning or audit trails.

C. Clarifications and Content

Appendix .C – Clarification and Content for Phase 1

The following responses and additional analysis and benchmarking have been provided as an outcome of the clarification discussion between Transpower and Mott MacDonald on the 13 October 2025. Therefore, this appendix should be read in conjunction with Report Phase 1 and the Report Phase 1 Comments Register.

Numbering is aligned with the comments register for ease of use. Additionally, the relevant section of Report 1 has been noted (where applicable). Comments A.1, A.3, A.4, B.1, E.2, G.1, G.2, item 2, and item 3 have not been included in this appendix as these were noted as *'further context/content not required'* during the clarification meeting.

Additional Clarification and Content

Response to Comment A.2 – Risk of Overinterpretation

Additional content/context for Section 1 of Report 1

Upon further review we acknowledge that the current BOE does have some light commentary around risk allowance. However, we believe there is value in ensuring that items around risk and assumptions are clearly referenced so that any user or reader can be immediately informed due to their sensitivity.

Response to Comment A.5 - Misapplication Risk Due to Level of Detail

Additional content/context for Section 1 of Report 1

After further clarification with Transpower we recognize that the model's intent was to reflect a coherent and internally consistent logic chain for internal use, therefore, internal familiarity would enable confident application.

Mott MacDonalds review findings are based on how the model could be misapplied outside the initial Transpower internal team, on the understanding that the models will potentially be used by others. To mitigate this risk, we suggest explicitly embedding reference to estimate class and underlying uncertainty within the tool's outputs or reporting templates. A visual cue or banner indicating "Class 5 estimate – not suitable for investment-grade decisions" or similar could preserve internal utility while ensuring broader stakeholders are not misled.

This would also align with AACE guidance on managing stakeholder perception of early-stage estimates.

Response to Comment A.6- The TEES Platform

Additional content/context for Section 1 of Report 1

Post review Mott MacDonald acknowledges Transpower's confidence in the underlying cost logic and understand that TEES-derived data has been developed with significant internal validation.

To ensure that the data considers international procurement market volatility, we recommend a periodic review process for TEES. Additionally the use of an explicit market float may also cover uncertainty and potential offshore uplifts making the model more robust and flexible. This does not imply a full market reset but introduces a validation cycle that keeps the tool robust under evolving delivery conditions.

We also recommend clearly documenting when TEES data was last validated externally and under what market conditions it was deemed current. This will ensure future users understand its context and limitations.

Response to Comment C.1- Escalation Modelling

Additional content/context for Section 4.2 of Report 1

We acknowledge Transpower's inclusion of AACE RP 56 to address systematic risks and agree that, at Class 5 level, the prominence of non-project-specific uncertainty is appropriate. However, we encourage ensuring that parameters applied in the tool—especially those related to escalation, market conditions, and generic property assumptions—are dynamic rather than static. While some static assumptions (e.g., fixed escalation rates or property cost loading) may be suitable in early estimates, they can hinder adaptability as project specifics emerge.

To address this, we suggest the tool could be further strengthened by enabling scenario testing and greater parameterisation. This would allow users to test the cost impact of fluctuating escalation rates, localised site constraints, and project-specific design choices. This approach would support more effective sensitivity testing and allow greater alignment with project delivery realities, particularly as projects transition from conceptual to more defined phases.

Response to Comment D.1- Accuracy and Range

Additional content/context for Section 4.3 of Report 1

Upon further discussion with Transpower, Mott MacDonald would like to clarify our finding that the cost tools are fundamentally accurate and suitable for high-level (Class 5) assessments.

Our recommendations are based on experience where we have found that outputs are derived from a single-point P50 reference. We have typically suggested the inclusion of light probabilistic treatment—such as basic Monte Carlo simulations or scenario testing—to help bound the results and reflect a range of possible outcomes.

These methods do not need to be complex or overly burdensome to implement but would go a long way in strengthening the credibility of the estimates. In particular, applying scenario-based variation to key drivers like escalation, consenting delay, or environmental approval risks would reduce the perception of precision beyond what is reasonably defensible at a Class 5 level.

Response to Comment D.2- Validation Methodology

Additional content/context for Section 4.3 of Report 1

Our validation approach compared model outputs against a suite of recent NZ and Australian projects, covering lines, substations, and rebuilds. In several cases, the divergence reflected:

- Scope differences (e.g. staged brownfield work versus greenfield assumptions in the model)
- Market timing (projects tendered at the peak of COVID-related escalation compared with TEES averages)
- Contracting strategy (alliancing vs EPC vs unit-rate contracting, which significantly impacts overhead and preliminaries)

To improve transparency, we propose documenting these differences explicitly in the BOE through a short validation appendix that:

- Lists the benchmark projects and their characteristics
- Explains variances and whether they are due to scope, timing, or contracting strategy
- Identifies which divergences should be adjusted for in the model, and which are legitimate context-based differences

This BOE appendix will ensure model outputs are traceable back to real-world benchmarks and provide clarity for decision-makers.

Response to Comment E.1- Brownfield Complexity's

Additional content/context for Section 4.4 of Report 1

With the current model not including brownfield complexities, property/consenting risks or engineering constraints, a simple solution would be to insert placeholder bands. This would provide cover until sufficient data is developed whilst also ensuring such costs don't get overlooked.

Response to Comment F.1- Use of Hard-coded/Static Inputs

Additional content/context for Section 4.5 of Report 1 (See also Response to Comment D.1)

We acknowledge that the current models use static escalation factors and some hard-coded inputs which limit internal sensitivity testing. To address this, we propose introducing more flexible input ranges for key parameters — particularly where market

dynamics and project-specific variations (e.g. brownfield vs greenfield) could materially affect outputs.

This change will enhance internal useability while also maintaining external rigour through continued application of clear disclaimers. We recognise that this is a distinct issue from misapplication risk, though both merit clear treatment.

Response to Comment F.2- Scenario Toggling – User Level

Additional content/context for Section 4.5 of Report 1 (See also Response to Comment D.1 and F.1)

The lack of toggles for changing assumptions — such as span length, brownfield constraints, or construction methodology — currently restricts the model's adaptability. Scenario toggling functionality would provide significantly greater flexibility and enable faster assessment of alternative delivery strategies.

We recommend prioritising the integration of this feature in the next model update, with a roadmap to progressively introduce toggles aligned with key project variables and decision points. We recognise that this is a distinct issue from misapplication risk, though both merit clear treatment.

Response to Comment F.3- Governance Control and QA

Additional content/context for Section 4.5 of Report 1

This is aligned with our broader observations on governance and validation. We recommend implementing a staged enhancement roadmap to progressively address these limitations. This includes:

1. Introducing stochastic or Monte Carlo-based risk treatments to better reflect delivery risk and uncertainty,
2. Establishing a formal QA/QC review cycle (see E1), and
3. Strengthening version control and change tracking protocols.

These steps will help reduce reliance on deterministic outputs and improve model defensibility in peer reviews or assurance processes.

Response to Comment G.3- Misapplication Risk

Additional content/context for Section 4.6 of Report 1

We acknowledge the concern and understand the AACE estimate classification system matrices allow for flexibility, however we also would like to clarify that our review did not find that a risk of misapplication of the tool makes it flawed as the misapplication risk does not sit at the mechanical level of the tool.

The risk sits with the end-user and their understanding and perception of the tool's mechanics. Noting that this risk may increase again if Transpower provide access to the

tool in its current form to a wider group of industry stakeholders. We suggest clearer disclaimers in model documentation, detailing the limitation to a screening level Class 5 modelling tool. This will help avoid overinterpretation while still supporting consultation objectives.

Response to Comment 1- Misapplication Risk

Additional content/context for Section 4.6 of Report 1

We understand the concern, however the solution is relatively straightforward as indicated in Response Comment G.3.

We propose drafting a short note in the BOE that explicitly clarifies the intended purpose of the models, outlines key risks if applied incorrectly and sets out how disclaimers and documentation will mitigate that risk. We are happy to co-develop the exact wording with Transpower to ensure it gives stakeholders the confidence and transparency required.

Response to Comment 4- New Benchmarking Analysis

Following the discussions between Mott MacDonald and Transpower, we have created a series of benchmarking tables below in response to the request for additional analysis around brownfield, temporary and staging works.

- Benchmark data for staging and temporary works cost allowances are centralised in Tables X.1 to X.3. These provide voltage-tiered comparisons across recent Australian projects and allow for brownfield uplift factors.
- Table X.4 now captures equipment-specific procurement durations based on recent Australian experience, and includes high-side switchgear, 220 kV/330 kV transformers, reactors, and GIS panels.
- Labour factors for brownfield vs greenfield delivery are benchmarked in Table X.5. This includes assumptions for constrained access, outage coordination, and additional safety supervision requirements.

It should be noted that global industry cost modelling practices currently view these assumptions and costs with a high level of sensitivity. Therefore, there are a number of industry workshops being undertaken to provide integrity and currency to these types of benchmarks.

Note that the UK look to be early adopters and have just released updates for two codes of practice in relation to these types of costs.

Table X.1 – Temporary Works Benchmarking by Voltage Class

Voltage Class	Temporary Works Allowance (% of EPC)	Typical Scope Items	Benchmark Range ($/km)
110 kV	3–5%	Access roads, temporary yards, fencing	$120k–$180k
220 kV	5–7%	Laydown, civil interfaces, temp supplies	$200k–$310k
330 kV	7–10%	Stage works, live access control	$320k–$450k

Table X.2 – Brownfield Enablement Cost Uplift vs Greenfield

Voltage Class	Enablement Uplift (%)	Scope Examples
110 kV	10–15%	Access rework, tie-ins, live interfaces
220 kV	15–25%	Reconfiguration, bund removal, compact layout
330 kV	25–35%	Staged demolition, significant isolation

Table X.3 – Delivery Duration Adjustment Factors (Brownfield)

Voltage Class	Nominal Duration (months)	Brownfield Delay Factor	Adjusted Duration Range
110 kV	12	x1.15–1.30	14–16 months
220 kV	15	x1.25–1.40	19–21 months
330 kV	18	x1.30–1.50	23–27 months

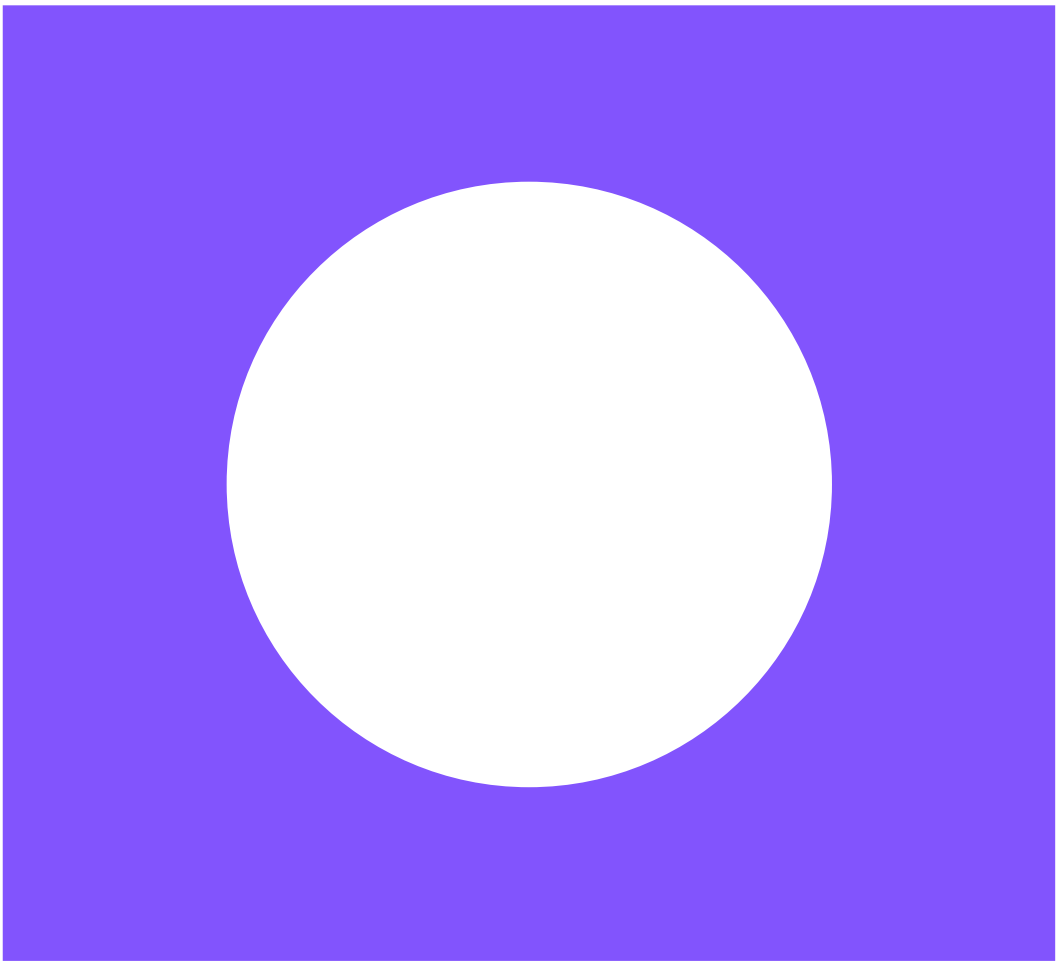
Table X.4 – Procurement Window Estimates (Australia, 2024)

Equipment Type	Lead Time (months)	Dependencies / Notes
220 kV Transformer	16–20	Design approval adds ~3 months
330 kV GIS Panels	14–18	Shipping and testing lead times
110 kV Switchgear	10–14	Subject to OEM availability
Reactors (220–330 kV)	15–19	Including FAT and transport

Table X.5 – Labour Loading Uplift: Brownfield vs Greenfield

Voltage Class	Labour Uplift (%)	Driver Factors	Mitigation Notes

110 kV	15–20%	Limited space, safety watch	Shift work, pre-task briefing
220 kV	20–30%	Stage works, live yard access	Night shifts, shadow work zones
330 kV	30–40%	Complex tie-ins, HV risks	Detailed staging, tiered induction



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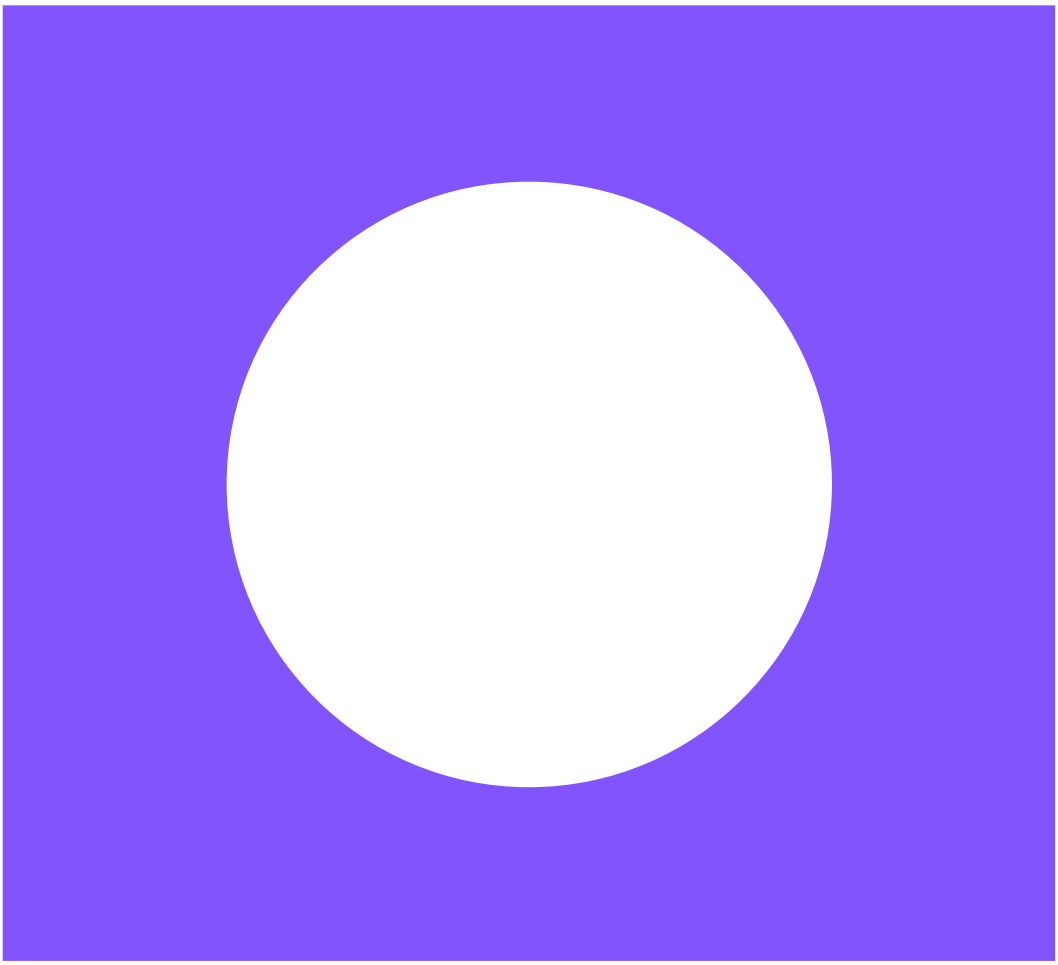

Transpower - High Level Cost Estimation Models Review

Phase 2 - Review of Cost Model Components

30/09/2025

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Transpower - High Level Cost Estimation Models Review

Phase 2 - Review of Cost Model Components

30/09/2025

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Contents

Review Inputs 3

Introduction 4

1 Executive Summary 5

2 Methodology Review 6

3 New Zealand Context 7

4 Basis of Estimate (BOE) – Expanded Review 8
- 4.1 Observed Primary Gaps in the Current BOE 9
- 4.2 Demonstrative Case Study 9
  - 4.2.1 Worked Example – Escalation Impact 9
- 4.3 Recommendations 10

5 Substation Cost Model – Expanded Review 11
- 5.1 Model Interpretation & Mapping 11
- 5.2 Granular Benchmark Library 12
- 5.3 Power Transformers – Unit Cost Bands 12
- 5.4 Switchgear & Bays – Unit Cost Bands 12
- 5.5 Benchmarking and Comparison with International Practices 13
- 5.6 Demonstrative Case Studies 14
  - 5.6.1 Worked Example – Benchmarked cost vs TP model 14
  - 5.6.2 Worked Example – Uplift Stacking 14
- 5.7 Recommendations 14

6 Cable Cost Model – Expanded Review 15
- 6.1 Benchmarking – Land Cable Supply & Install 15
- 6.2 Benchmarking – Trenchless Crossings 15
- 6.3 Benchmarking – Submarine Cable 16
- 6.4 Benchmarking – Landfalls & Jointing 16
- 6.5 Benchmarking – Property, Brownfield & O&M 17
- 6.6 Demonstrative Case Study 17
  - 6.6.1 Worked Example – HV cable urban trench benchmark 17
- 6.7 Recommendations 18

7 HVDC Station Cost Model – Expanded Review 19
- 7.1 Converter Equipment 19
- 7.2 Control, Protection & Communications 19

7.3 Civil Works & Building 20
7.4 Ancillary Systems & O&M 20
7.5 Demonstrative Case Study 21
7.5.1 Worked Example – HVDC convertor station benchmark 21
7.6 Recommendations 21

8 Line Upgrade Cost Model – Expanded Review 23
8.1 Reconductoring Benchmarks 23
8.2 Structure Interventions 24
8.3 Enabling Works & Environmental 24
8.4 Property & Stakeholder Costs 24
8.5 Corridor Class P50 Checks (220 kV) 25
8.6 Demonstrative Case Studies 25
8.6.1 Worked Scenario 25
8.7 Recommendations 26

9 New Transmission Line Cost Model – Expanded Review 27
9.1 Structures & Foundations 27
9.2 Conductors 28
9.3 Access & Enabling Works 28
9.4 Property, Easements & Environmental 29
9.5 Corridor Class Benchmarks 29
9.6 Demonstrative Case Studies 30
9.6.1 Worked Scenario 30
9.6.2 Input Assumptions (new line) 30
9.7 Recommendations 31

10 Assumptions and Exclusions 32

11 Conclusions 33
11.1 Demonstrative Case Studies Summary Table 33
11.2 Summary of Recommendations 34

A. Transpower Review Comments 35

B. Clarification and Content 36

Review Inputs

File Name	Description
Basis of Estimate - Future Grid (V1)	Basis of Estimate
20250715_New_Substation_Cost_Model_Draft	New Substation Cost Model
20250730_New_Cable_Cost_Model_Draft	New Cable Cost Model
20250811_New_HVDCStation_Cost_Model_Draft	New HVDC Cost Model
20250820_Line_Upgrade_Cost_Model_Draft	Line Upgrade Cost Model
20250820_New_Line_Cost_Model_Draft	New Line Cost Model

Introduction

Transpower's Te Kanapu (Future Grid) initiative represents a bold and necessary vision for New Zealand's transmission system future. The Future Grid programme is a strategic initiative aimed at coordinated long-term planning, focusing on long-term investments such as new lines.

We fully appreciate the importance of developing streamlined, consistent, and user-friendly cost models to support preliminary planning decisions for the network of the future shaped by decarbonisation, electrification, resilience, and distributed generation. We also understand Transpower's requirement to have 'overnight' capital costs as the primary outputs from the cost models, while additionally identifying escalation drivers to future-proof strategic modelling as needs evolve.

Transpower has provided five separate Excel cost models for review as follows:

- New AC transmission lines;
- New DC links;
- New AC substations;
- New underground and subsea cables; and
- Upgrade of an existing line.

A Basis of Estimate has been prepared by Transpower to give context and outline the principals used to develop the models, which we have similarly reviewed.

The Phase 1 was to undertake a holistic review of models, and the outcomes were presented in our report dated 17 Sept 2025. This Phase 2 report provides a summary recommendation resulting from component cost review and validation of draft cost models.

1 Executive Summary

This Phase 2 cost component review builds on the initial Phase 1 holistic review of Transpower's Basis of Estimate (BOE) and cost models. Where Phase 1 focused on structure and methodology, this phase report provides a technical dive into cost completeness, benchmarking, missing Class 5 drivers, and risk of misapplication. The discussion for each model (substations, transmission lines, cables, HVDC, line upgrades, new lines), along with the BOE, has been expanded to provide detailed analysis, and variance commentary.

In addition to this we have presented worked examples as 'Demonstrative Case Studies' for each cost model to illustrate the practical application of the model. These examples are not additional analyses; rather, they serve as demonstrative case studies, showing how the cost components behave under realistic scenarios. By doing so, they bridge the technical benchmarking with observable outcomes, providing confidence in the credibility and usability of the models at Class 5 level.

The review work, and associated recommendations are with respect to models that deliver Class 5 outputs for initial project screening purposes. Our review concludes that although certain mechanics (e.g., WBS-style outputs) mimic Class 3, the underlying inputs and escalation logic remain high-variance, the end result can be construed as a fit-for-purpose Class 5 model.

We understand Transpower will consider further the strategic aims / output required of the models, along with the approach and context for releasing the models to wider stakeholders. We would be happy to subsequently refine or expand our recommendations accordingly based on Transpower's further feedback.

Should the intent be to make the model widely available to multiple end-user groups, it may be beneficial that a number of the recognised systemic omissions discussed in this report be reviewed for its completeness.

2 Methodology Review

The phase 2 analysis was guided by AACE International estimate classifications. The reviewed models align with Class 5, with a variance band of –50% to +100%. While WBS-style outputs and component breakdowns give an impression of Class 3, the lack of design maturity, benchmarking rigour, and probabilistic escalation confirm Class 5 classification. Benchmarks used are directional and validated against AEMO, CIGRÉ, Ofgem, Hydro-Québec, and EU ACER sources. To address applicability to New Zealand, we adjusted international benchmarks using MBIE and Stats NZ construction input indices. This triangulation ensured defensible directional accuracy. The Phase 2 review focused on five key scope questions:

- Are all relevant cost components included?
- Are component costs reasonable when benchmarked externally?
- Should new cost components be introduced?
- How should escalation be treated?
- How can building blocks and implementation support be improved?

3 New Zealand Context

Cost estimations need to reflect the reality that there is a fixed pool of qualified maintenance contractors in New Zealand, who carry out both routine maintenance work and construction work for Transpower projects - such as grid upgrades, assets relocation and infrastructure changes. The NZ context includes:

- **Fixed Contractor Pool** – There are limited contractors with the capability, qualifications and safety accreditation to work on Transpower's network. This means labour is constrained, and contractor availability and scheduling significantly affect cost and time estimates. Also, only Transpower approved international suppliers (e.g., transformers, conductors, hardware etc) are engaged.
- **Integrated Maintenance and Construction** – The same contractors who perform routine grid maintenance are also responsible for major construction works. The cost estimation should therefore factor in opportunity costs, scheduling conflicts and priority trade-offs.
- **Geographic factors** – in New Zealand, mostly projects are in remote locations so mobilisation, transport, accommodation and logistics also need to be factored into cost estimations.
- **Regulatory approvals** – all construction work needs to meet NZ regulatory requirements (health and safety, building codes, environmental regulations) which can influence both time and cost.

4 Basis of Estimate (BOE) – Expanded Review

The Basis of Estimate (BOE) prepared by Transpower is a credible starting point for establishing a Class 5 cost modelling framework. It demonstrates clear intent to provide a transparent foundation for the development of cost models across transmission assets and reflects an awareness of AACE International's estimate classification system.

At its core, the BOE establishes structure and governance, which is critical for early-stage modelling. However, as with many Class 5 BOEs, several areas can be strengthened to ensure that the models remain both fit-for-purpose and clearly labelled to prevent misapplication. Importantly, our view is that the BOE should be seen not as flawed, but as a sound skeleton requiring additional muscle to deliver resilience in optioneering and to support decision-making under uncertainty.

Table 1 Benchmarking and Comparison with international BOEs

Aspect	Transpower BOE	International Practice	Benchmark Reference
Variance Range	–31% to +57%	AACE Class 5: –50% to +100%	AACE 17R-97
Escalation	Flat 2–3% p.a.	Indexed to construction / labour indices (MBIE, ABS, Eurostat)	AEMO TCD 2025; Ofgem 2023
Scope Coverage	Capex focus on primary assets	Placeholders for O&M, consenting, brownfield	Ofgem RIIO-2 BOE; Hydro-Québec 2023
Assumptions	Narrative descriptions	Structured assumptions registers	AEMO TCD Assumptions Library
Risk Treatment	Generic % uplift	Risk-based placeholders + Monte Carlo	PJM Cost Estimation Guide 2022
Property	40% blanket uplift	8–12% typical; region and corridor dependent	Ofgem RIIO-2; Hydro-Québec BOE 2023
Brownfield	Not explicit	Additional 10-15% staging / mitigation costs; access, outage management, demolition	CIGRÉ TB 815; UK National Grid Projects
Terrain	Not explicit	Corridor-specific adjustments (e.g. +5-10% for mountainous/rocky ground; 2-5% for plains)	AEMO ISP assumptions 2022; FERC filings

O&M	Absent	Typically 1-2% of CAPEX annually included as placeholder for lifecycle costing	Ofgem RIIO-2; Hydro-Québec BOE 2023

4.1 Observed Primary Gaps in the Current BOE

1. **Escalation Treatment** – Flat 2–3% p.a. understates volatility. MBIE indices show 5–7% p.a.; electrical equipment trending 8–10%.
2. **Property, Consenting & Stakeholder Engagement Costs** – Absent. Ofgem RIIO-2 projects allocate 5–8% to this category.
3. **Brownfield Staging Costs** – Not explicit. CIGRÉ TB 815 shows 10–15% additional staging costs in brownfield projects.
4. **O&M Considerations** – Absent. Hydro-Québec includes O&M placeholders of 1–2% of capex annually.

4.2 Demonstrative Case Study

4.2.1 Worked Example – Escalation Impact

Scenario: A 500 kV HVDC converter station is costed at NZD $520m (base 2025).

- Using flat 2.5% escalation: cost in 2030 = $589m.
- Using MBIE indices (avg. 6%): cost in 2030 = $696m.
- Variance: $107m understatement (18%).

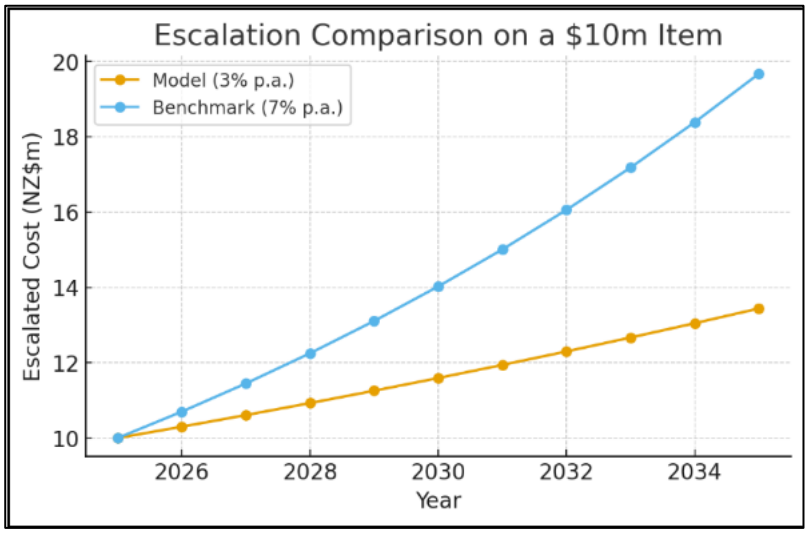


Figure 1: Escalation treatment example

Per the example shown in Figure 1 comparing 3% per annum escalation (TP cost model) with 7% per annum escalation (International benchmark), Transpower's models potentially under-forecast the estimated cost by 25% in Year 10.

4.3 Recommendations

- Retain Class 5 classification: the BOE is an appropriate framework aligned with AACE guidelines.
- Escalation: adopt dual-stream escalation; civils tied to MBIE indices, electricals tied to IHS/commodity indices.
- New Cost Components: introduce placeholders for property, consenting, and brownfield staging.
- Assumptions Register: shift to structured register format, e.g. per the following table:

Table 2 Risk Treatment

Risk Category	Examples	Treatment (Current - Recommended)
Technical	Seismic, harmonics, thermal ratings	Flat % - Calibrated risk distributions
Property	Injurious affection, access, legal	Flat % → Region-based cost/time impacts
Delivery	Outages, logistics, vendor lead	Absent → Allowances & schedule risk
Market	Steel/copper/freight volatility	3% → Indexed escalation & scenarios

5 Substation Cost Model – Expanded Review

The model is intended to function as a Class 5 screening tool, providing order-of-magnitude costing to support planning and high-level decision-making, and in its current draft it largely functions as intended.

The substation model covers several primary cost categories one would expect to see in a Class 5 i.e., transformers, GIS/AIS bays, and site civil works. However, in comparison to international practice the model omits or is not clear on cost categories that can have significant impact on the models output. A number of these missing categories typically only require placeholder information but nonetheless they should be included. This includes brownfield works, temporary staging, cyber security, fire/auxiliaries, and environmental factors.

The substation workbook includes major components such as transformer bays, bus couplers, disconnectors, switchgear, protection systems, control buildings, and supporting civil works such as earthworks, access, and drainage. Overheads are applied through standard percentage uplifts: 15% design cost, 10% Transpower overheads, 25% contractor overheads, 25% risk allowance, and a 40% property risk uplift. Escalation is currently applied at a flat 2–3% per annum.

Additionally, if the model is to be used beyond its current sphere (in a format yet undecided), to avoid misapplication users must be fully aware that it is clearly stated within the BOE to be a Class 5 tool for screening purposes only. This is due to the potential of inexperienced users mistaking several of the models' traits and characteristics for that of Class 3 mechanics i.e., the WBS-style breakdown (bay-by-bay, equipment-level).

5.1 Model Interpretation & Mapping

Transpower workbook components are mapped to benchmark categories as follows:

Table 3 Benchmark Transpower workbook

Workbook Component	Benchmark Category	Notes / Mapping Guidance
Major Plant	Power Transformers	Map per voltage / MVA class; include tap changers, auxiliaries where applicable
Bay Costs (GIS/AIS)	Switchgear & Bays	Cost per bay by voltage; include busbars, disconnectors, CT/VT sets
Secondary Systems	Protection, Control, SCADA, Telecoms	Percent of total and / or per-bay / per-transformer allowances

Civils	Earthworks, Foundations, Pavements, Drainage, Trenches, Buildings	Disaggregate to modules for better scaling
Property	Property & Consenting	Treat as % of total; corridor/urban modifiers
Risk/Overheads	Preliminaries, OH&P, Risk	Keep as separate line items at Class 5

5.2 Granular Benchmark Library

In line with Class 5 estimating practice, benchmark tables are presented below to compare the current Transpower model outputs against a range of international references, including AEMO's Transmission Cost Database (2025), Ofgem RIIO-2 cost allowances, and CIGRÉ technical brochures. These tables are intended as screening-level checks, showing low–high cost bands and midpoint values across asset classes. By positioning Transpower's figures within these ranges, we can ensure that the models are both credible and consistent with international practice while recognising the inherent uncertainty of Class 5 estimates.

5.3 Power Transformers – Unit Cost Bands

Table 4 Power Transformer - Unit cost bands

Voltage Class / Rating	Typical Application	Benchmark Range (NZD/unit)	Benchmark Midpoint	Brownfield Modifier	Benchmark Source
110/33 kV, 120–200 MVA	GXP step-down	$8m – $14m	$11m	+5–10%	AEMO TCD 2025; CIGRÉ TB 851
220/110 kV, 200–300 MVA	Inter-grid substations	$12m – $22m	$17m	+7–12%	AEMO TCD 2025; IHS vendor
400/220 kV, 300–500 MVA	Backbone grid	$20m – $35m	$27.5m	+8–15%	CIGRÉ TB 851; EU tenders

5.4 Switchgear & Bays – Unit Cost Bands

Table 5 Switchgears & Bays - Unit Cost Bands

Bay Type	Voltage	Benchmark Range (NZD/bay)	Midpoint	Brownfield Modifier	Benchmark Source

GIS Bay	220 kV	$1.8m – $3.0m	$2.4m	+5–10%	AEMO TCD 2025; MM TCD upd.
GIS Bay	110 kV	$1.2m – $2.2m	$1.7m	+5–10%	AEMO TCD 2025; Ofgem RIIO-2
AIS Bay	220 kV	$1.0m – $1.8m	$1.4m	+3–8%	CIGRÉ TB 604; AEMO
AIS Bay	110 kV	$0.7m – $1.3m	$1.0m	+3–8%	CIGRÉ TB 604

5.5 Benchmarking and Comparison with International Practices

Table 6 Benchmarking and comparison with International Practices

Component	Transpower Model	Benchmark Range (NZD)	Benchmark Midpoint	Source / Note
Transformer 220/110 kV, 250 MVA	$7m	$12m – $22m	$17m	AEMO TCD 2025; CIGRÉ TB 851
Transformer 400/220 kV, 400 MVA	$11m	$20m – $35m	$27.5m	CIGRÉ TB 851; EU tenders
GIS Bay 220 kV	*Not explicit	$1.8m – $3.0m	$2.4m	Ofgem RIIO2; AEMO TCD 2025
GIS Bay 110 kV	*Not explicit	$1.2m – $2.2m	$1.7m	AEMO TCD 2025; Ofgem RIIO2
AIS Bay 220 kV	*Not explicit	$1.0m – $1.8m	$1.4m	CIGRÉ TB 604; AEMO
AIS Bay 110 kV	*Not explicit	$0.7m – $1.3m	$1.0m	CIGRÉ TB 604
Secondary Systems (per bay)	*Not explicit	$0.20m – $0.40m	$0.30m	PJM/ERCOT; Ofgem RIIO2
Control Building (gross per m²)	*Not explicit	$3,500 – $5,000	$4,250	HydroQuébec; Ofgem projects

***** Clear costs cannot be inferred from the model i.e., direct costs associated with different types of similar assets or asset type segregation is not clear or are not stated.

5.6 Demonstrative Case Studies

5.6.1 Worked Example – Benchmarked cost vs TP model

Scenario: A 220/110 kV substation with 2×250 MVA transformers and 6 GIS bays. Benchmark midpoint NZD $82m. Transpower model (New Substation Cost Model) $65m was compared to calculate variance of 21%. Brownfield omission risks understatement by 10–20%.

5.6.2 Worked Example – Uplift Stacking

The term ‘uplift stacking’ refers to the compounding of multiple blanket uplifts across design, contractor overheads, risk, and property allowances. When applied sequentially rather than discretely, these uplifts can inflate a base cost far beyond the original estimate. The following worked example illustrates this effect in practice. Figure 2 shows how blanket percentages compound quickly. This example inflates $100 to $273 before any contingency, tied to real risks.

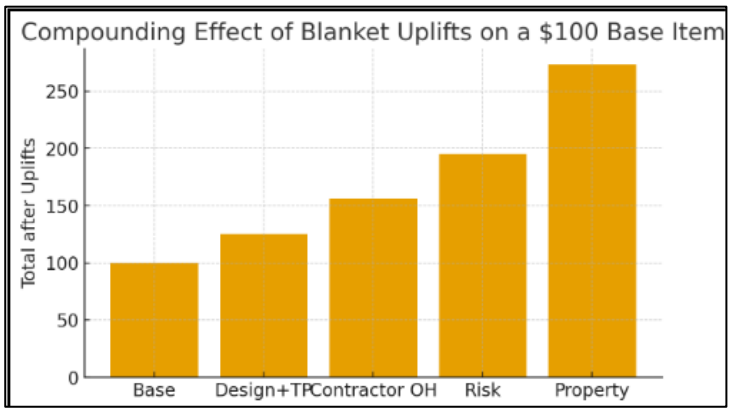


Figure 2: Uplift stacking example

5.7 Recommendations

- Addition of auxiliaries as placeholders.
- Brownfield staging costs to be considered as these can add a further 10-15% cost to project
- Benchmarking review of all cost components.
- Apply NZ PPI and IHS indices.
- Expand building block descriptors (major plant, civils, secondary, auxiliaries).

Optional upgrades could also include vendor-backed rates, probabilistic outage staging, and component-level modelling.

6 Cable Cost Model – Expanded Review

The cable model covers supply, trenching, joints, high-voltage AC XLPE land cables and submarine HVAC segments. However, this model omits installation method differentiation (open cut vs HDD vs micro tunnel), urban vs rural reinstatement, landfall/marine works, thermal backfill, spoil management, transition joint bays, auxiliaries, and environmental.

At Class 5 level, the models' purpose is to provide screening-grade order of magnitude costs for strategic decision-making. Cable projects are particularly sensitive to corridor context (urban vs rural), trench type, seabed conditions, and vessel availability. Our review expands on benchmarking, adds narrative on cost drivers, and identifies gaps where Transpower's model could understate or overstate costs.

6.1 Benchmarking – Land Cable Supply & Install

Land AC XLPE cable costs are primarily driven by conductor material, voltage class, trench depth/width, and reinstatement. Urban settings demand more for traffic management and reinstatement. Thermal backfill requirements can add 5–10%.

Table 7 Benchmarking Land Cables

Component	Transpower Model	Benchmark Range (NZD)	Benchmark Midpoint	Source / Note
Rural trench (220 kV)	*Not Explicit	$6m – $9m	$7.5m	AEMO TCD 2025; EU ACER 2023
Urban trench (220 kV)	*Not Explicit	$10m – $14m	$12m	Ofgem 2023; EU ACER 2023
Rural trench (110 kV)	*Not Explicit	$4m – $7m	$5.5m	AEMO TCD 2025

* Clear costs cannot be inferred from the model (i.e., direct costs associated with different types of similar assets or asset type segregation is not clear or are not stated).

6.2 Benchmarking – Trenchless Crossings

Trenchless crossings such as HDD and micro-tunnels are critical cost elements that vary by ground condition and risk of collapse. HDD is typically cheaper for short lengths, while micro-tunnels suit dense utility corridors.

Table 8 Benchmarking Trenchless Crossings

Component	Transpower Model	Benchmark Range (NZD)	Benchmark Midpoint	Source / Note
HDD crossing	*Not Explicit	$3,000 – $6,000/m	$4,500/m	CIGRÉ TB 852; contractor norms

Micro-tunnel crossing	*Not Explicit	$6,000 – $12,000/m	$9,000/m	CIGRÉ TB 852; utility norms

* Clear costs cannot be inferred from the model

6.3 Benchmarking – Submarine Cable

Submarine Cable costs are dominated by vessel mobilisation, seabed preparation, and landfalls. Mobilisation can exceed NZD 10m. Weather delays add further escalation risk. For clarity, 'main lay' refers to continuous offshore installation of submarine cable lengths, as distinct from nearshore works. International benchmarks (CIGRÉ TB 852, EU ACER 2023) identify significant cost differences between the two, with main lay typically in the range of NZD 18–25m per 100 km and nearshore segments NZD 20–28m per 100 km.

Table 9 Benchmarking - Submarine Cable

Component	Transpower Model	Benchmark Range (NZD)	Benchmark Midpoint	Source / Note
Nearshore (≤1 km)	*Not explicit	$20m – $28m	$24m	CIGRÉ TB 852; EU ACER 2023
Offshore main lay	*Not explicit	$18m – $25m	$21.5m	CIGRÉ TB 852; EU ACER 2023

* clear costs cannot be inferred from the model

6.4 Benchmarking – Landfalls & Jointing

Landfalls are among the most complex cable elements, typically using HDD. Jointing compounds must allow for spares and operations. These are often underestimated in cost models both locally and internationally.

Table 10 Benchmarking - Landfill & Jointing

Component	Transpower Model	Benchmark Range (NZD)	Benchmark Midpoint	Source / Note
Landfall (HDD, per bore)	*Not explicit	$3m – $7m	$5m	CIGRÉ 852; contractor norms
Onshore joint bay/compound	*Not explicit	$0.8m – $1.8m	$1.3m	Utility norms; AEMO TCD
Spare joint sets	*Not explicit	$0.2m – $0.4m	$0.3m	Utility practice

* Clear costs cannot be inferred from the model

6.5 Benchmarking – Property, Brownfield & O&M

Urban cable projects face additional property and consenting costs, typically 5–10% is allowed for that. Brownfield congestion and traffic management can add 10–20% to cost. Lifecycle O&M is generally 1–2% capex p.a. as a nominal uplift.

Table 11 Benchmarking - Property

Component	Transpower Model	Benchmark Range (NZD)	Benchmark Midpoint	Source / Note
Property/Consenting	*Not explicit	5% – 10%	7.5%	Ofgem RIIO-2; Hydro-Québec
Brownfield (urban congestion)	*Not explicit	10% – 20%	15%	CIGRÉ 815; municipal norms
Traffic Management	*Not explicit	5% – 10%	7.5%	Municipal norms
O&M Placeholder (annual)	*Not explicit	1% – 2% capex p.a.	1.5%	Hydro-Québec; Ofgem

* Clear costs cannot be inferred from the model

6.6 Demonstrative Case Study

6.6.1 Worked Example – HV cable urban trench benchmark

Scenario: for a 10 km 220 kV XLPE urban trench the benchmark midpoint $12m/km. Transpower's cable cost model output is $9.25m/km; a variance of -23% for the model.

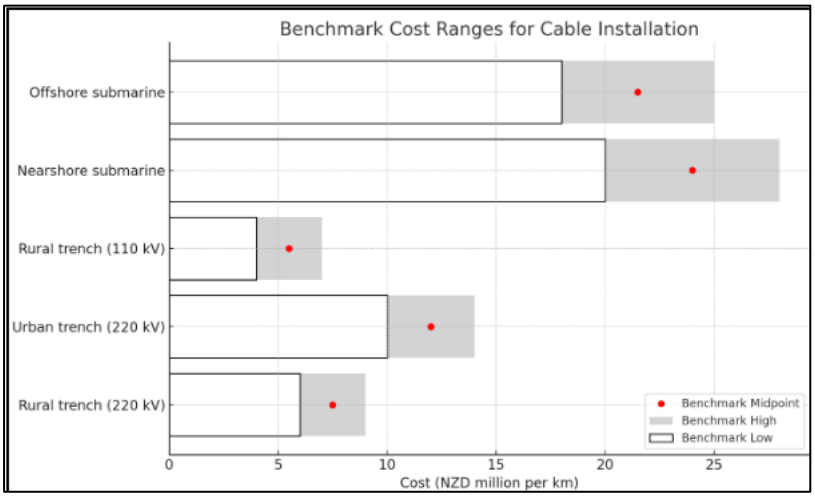


Figure 3: HV cable installation benchmark cost range

6.7 Recommendations

- Addition of selectors for method/environment, landfalls, TJB/SECs, thermal backfill.
- Apply dual-stream escalation (commodity vs labour).
- Expand scope descriptors.
- Escalate material costs using MBIE indices.
- Drive quantities from route engineering (burial, joints, HDDs) and vendor quotes.
- Regionalise property costs; include injurious affection explicitly.
- Apply copper, XLPE, vessel day-rate indices; benchmark against Cook Strait & international interconnectors.

In addition to tightening the above primary drivers, several of which have elements of them within the current model, there are other cost drivers that one could include that may help materially improve realism while preserving Class 5 costing. These include vendor-backed bills, probabilistic HDD/marine risks, and detailed thermal modelling.

7 HVDC Station Cost Model – Expanded Review

The HVDC station cost model addresses converter stations, valve halls, transformers, smoothing reactors, control/protection, and auxiliary systems. At Class 5 level, the models' purpose is to provide order-of-magnitude costs for strategic screening of HVDC options. HVDC projects are particularly capital-intensive, with significant drivers from specialised equipment and labour costs. The model itself provides high-level lump sums with limited breakdown. Missing categories include civil/site preparation, geotechnical considerations, auxiliary buildings, harmonic filters, cooling, protection & control, and spares.

However, while the converter transformer rates are plausible that are arguably outdated; valve halls costed as lump sums understate international benchmarks, and seismic uplift of 50% is applied flatly.

7.1 Converter Equipment

Converter equipment typically forms the largest share of HVDC station costs. Valve halls and valves are highly specialised, with costs varying by technology (LCC vs VSC), power rating, and vendor. Converter transformers are critical long-lead items, and are sensitive to copper/steel prices. Smoothing reactors are essential for current control and harmonic filtering.

Table 12 Convertor Equipment

Component	Transpower Model	Benchmark Range (NZD)	Benchmark Midpoint	Source / Note
Valve Hall & Valves (±500 kV, 1000 MW)	*Not explicit	$250m – $400m	$325m	CIGRÉ TB 851; EU projects
Converter transformers (per set, ±500 kV)	*Not explicit	$80m – $120m	$100m	AEMO TCD 2025; CIGRÉ TB 851
Smoothing Reactors	*Not explicit	$20m – $35m	$27.5m	Vendor data; CIGRÉ references

* Clear costs cannot be inferred from the model (i.e., direct costs associated with different types of similar assets or asset type segregation is not clear or are not stated).

7.2 Control, Protection & Communications

Control and protection systems are critical for system stability and safety. These costs cover digital control platforms, SCADA integration, protection relays and instrument transformers, and redundant communication systems. International benchmarks highlight variability depending on cybersecurity requirements and integration complexity.

Table 13 Control, Protection & Communication

Component	Transpower Model	Benchmark Range (NZD)	Benchmark Midpoint	Source / Note
Control & Protection Systems	*Not explicit	$30m – $60m	$45m	PJM/ERCOT; vendor practice
Communications & SCADA integration	*Not explicit	$15m – $30m	$22.5m	Ofgem RIIO-2; utility practice

* clear costs cannot be inferred from the model

7.3 Civil Works & Building

Civil works include valve hall and control buildings, earthworks, and foundations. Site conditions strongly affect these costs, with brownfield locations often incurring significant remediation. Hydro-Québec and European projects provide benchmark data, while AEMO's TCD outlines building block costs.

Table 14 Civil Works & Building

Component	Transpower Model	Benchmark Range (NZD)	Benchmark Midpoint	Source / Note
Valve Hall Building	*Not explicit	$40m – $70m	$55m	CIGRÉ TB 851; Hydro-Québec
Control Building	*Not explicit	$10m – $20m	$15m	Utility norms
Foundations & Earthworks	*Not explicit	$30m – $60m	$45m	AEMO TCD 2025; civil norms

* clear costs cannot be inferred from the model

7.4 Ancillary Systems & O&M

Ancillary systems such as auxiliary AC/DC systems, spares, and commissioning are essential for reliability. These often represent 10–15% of total station cost but are under-represented in high-level models. O&M placeholders should be 1–2% of capex per annum.

Table 15 Ancillary Systems and O&M

Component	Transpower Model	Benchmark Range (NZD)	Benchmark Midpoint	Source / Note
Auxiliary AC/DC Systems	*Not explicit	$10m – $25m	$17.5m	Vendor data; utility practice

Spare Parts & Commissioning	*Not explicit	$20m – $35m	$27.5m	Utility practice
O&M Placeholder (annual)	*Not explicit	1% – 2% of capex p.a.	1.5%	Hydro-Québec; Ofgem RIIO-2

* clear costs cannot be inferred from the model

7.5 Demonstrative Case Study

7.5.1 Worked Example – HVDC convertor station benchmark

Scenario: The benchmark midpoint for a 500 kV converter station is ~$520m. Transpower's HVDC model cost output is $600m, or a +15% variance from the model.

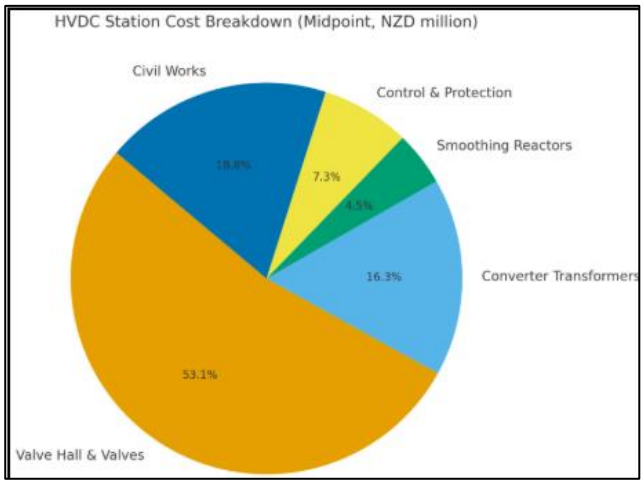


Figure 4: HVDC station cost breakdown chart

7.6 Recommendations

- Add placeholders for civils, auxiliaries, filters, cooling, O&M/spares.
- Update costs against IHS and recent HVDC projects.
- Apply multi-stream escalation.
- Disaggregate equipment (valves, transformers, reactors) and civil works rather than aggregating under EPC.
- Incorporate ancillary systems explicitly (auxiliary AC/DC, spares, commissioning).
- Apply dual-stream escalation for civil vs equipment supply.

In addition to these recommendations several optional upgrades would add further credibility to the model if included, such as vendor-backed rates, probabilistic seismic, and lifecycle cost modelling.

8 Line Upgrade Cost Model – Expanded Review

The Line Upgrade Cost Model has been developed as a Class 5 screening tool, intended to support high-level optioneering and early-stage investment planning. Consistent with other models in the suite, the model it provides structured parametric drivers, quantifiable inputs, and a transparent methodology that allows rapid comparison of upgrade scenarios. The model is clear and systematic in its treatment of spans, property impacts, overheads, and risk percentages, which strengthens its utility at this level.

However, several critical cost components are absent or under-developed including property/consenting costs, environmental and permitting considerations, and O&M consequences. These omissions limit the model's ability to capture the full range of upgrade project dynamics. The current approach also applies flat escalation and aggregated overheads, which, while adequate for Class 5 screening, may be misinterpreted as Class 3-level outputs due to the structured format of the model.

8.1 Reconductoring Benchmarks

Reconductoring is the dominant driver of line upgrade costs. The Transpower model applies a fixed base unit rate, which is transparent but lacks differentiation for conductor type and corridor complexity. International benchmarks show a widespread variance, reflecting commodity price exposure and HTLS technology premiums.

Table 16 Reconductoring Benchmarks

Driver	Transpower Model	Benchmark Range (NZD/cct-km)	Benchmark Midpoint	Source/Notes
Base reconductoring (220 kV)	*Not explicit	$0.75m – 1.10m	$0.93m	AEMO TCD 2025, Hydro-Québec
HTLS reconductoring	*Not explicit	$0.95m – 1.40m	$1.18m	CIGRÉ TB 852
Conductor supply	In base	$0.25m – 0.40m	$0.33m	Commodity indexed
Stringing labour & plant	In base	$0.20m – 0.50m	$0.35m	Terrain dependent

* Clear costs cannot be inferred from the model (i.e., direct costs associated with different types of similar assets or asset type segregation is not clear or are not stated).

8.2 Structure Interventions

Structure interventions are often underestimated in early-stage models but can contribute significantly to upgrade budgets, especially where thermal uprating drives higher mechanical loadings. The current model embeds these in lump-sum allowances, while international practice distinguishes between strengthening, replacement, and fitting upgrades.

Table 17 Structure Interventions

Item	Current Treatment	Benchmark Range (NZD)	Screening Driver
Structure strengthening	Lump	$22k – 45k / structure	% of suspension needing upgrade (10–35%)
Pole replacements	Lump	$55k – 180k / structure	Age/condition proxy
Insulator & fittings	Embedded	$4k – 10k / structure	30–60% of structures

8.3 Enabling Works & Environmental

Enabling works — including access, crossings, and environmental mitigation — are critical determinants of project feasibility. The current model reflects some allowances but does not scale adequately with corridor overlays or terrain. Benchmarks suggest a wide range, particularly for steep terrain or environmentally constrained corridors.

Table 18 Enabling Works & Environmental

Item	Benchmark Range (NZD)	Driver
Clearance rectification	$4k – 12k / span	% spans affected (5–40%)
Crossing span protection	$18k – 65k / crossing	Count per 10 km (3–12 typical)
Access track upgrades	$80k – 220k / km	Terrain factor (flat ↔ steep)
EPM mitigation	$80k – 250k / 10 km	Corridor overlays

8.4 Property & Stakeholder Costs

Property acquisition and stakeholder engagement are under-represented in the current model. While injurious affect and easements are included, planning approvals and structured engagement with landowners are not. International regulators such as Ofgem (RIIO-2) and AEMO include explicit allowances for these at Class 5.

Table 19 Property and Stakeholder Costs

Component	Current Model	Benchmark Range (NZD)	Notes
Injurious affect	Present	$20k – 300k / km	Corridor dependent
Easements	Present	$25k – 80k / parcel	Higher peri-urban
Stakeholder engagement	Missing	1.5–3% of direct	Project-level
Planning/approvals	Missing	0.8–1.5% of direct	Hearing risk

8.5 Corridor Class P50 Checks (220 kV)

Benchmark checks by corridor class ensure that modelled outputs remain credible when compared with international experience. These bands provide order-of-magnitude anchors for P50 estimates across rural flat, rural steep, and urban/ constrained environments.

Table 20 Corridor Class P20 Checks

Corridor Class	220kV Cost Range (NZD/cct-km)	Notes
Rural – Flat	$0.85m – 1.15m	Minimal access
Rural – Steep	$1.05m – 1.40m	High access, geotech
Urban/Constrained	$1.20m – 1.70m	Traffic, outages, property

8.6 Demonstrative Case Studies

8.6.1 Worked Scenario

Scenario: The benchmark midpoint for reconductoring a 30 km 220 kV line is ~$1.0m/km. Transpower's line upgrade model's output of $0.83m/km is about 17% below the benchmark.

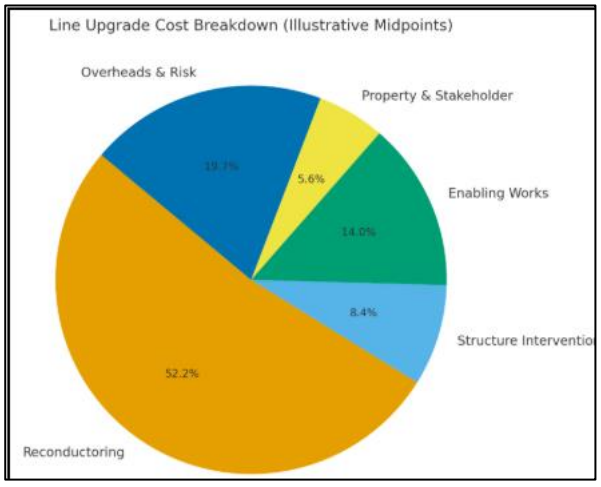


Figure 5: Line upgrade cost ranges and breakdown charts

8.7 Recommendations

- Add placeholders for outage staging.
- Rebase costs using commodity indices.
- Introduce terrain and climatic loading logic; calibrate structure counts; expand property modules; populate escalation; validate against recent 220/400 kV builds.

The Line Upgrade Cost Model is a solid Class 5 screening tool, fast and transparent. However, it arguably under-reflects corridor difficulty, staging, and property/consenting. Minimal adjustments (corridor switches, TTU/property placeholders) improve credibility without moving away from a Class 5.

9 New Transmission Line Cost Model – Expanded Review

The new line cost model provides screening-grade estimates for greenfield transmission line development.

The Model is suitable for Class 5 screening but risks underestimation in challenging terrain or urban corridors. Strengths include: a clear breakdown of major cost elements and transparent scaling with length. Weaknesses include lack of terrain multipliers, missing brownfield tie-in allowances, and under-representation of environmental and property costs.

The transmission line model is structured on tower spans and conductor configurations; however benchmarks (AEMO ISP 2024, Hydro-Québec 2023) indicate unit costs are 10–20% understated.

9.1 Structures & Foundations

Structures and foundations represent one of the highest cost drivers for new line construction. Costs vary significantly depending on voltage class, structure type, and terrain/geotechnical conditions.

The Transpower model uses averaged values, which are transparent but insufficiently granular. International benchmarks such as the AEMO Transmission Cost Database (TCD) 2025 and CIGRÉ Technical Brochure 815 (High-Voltage Overhead Line Design) show suspension tower costs ranging from NZD 180k–250k at 220 kV and up to NZD 480k at 500 kV, with foundations contributing an additional 20–30% depending on ground conditions.

Table 21 Structures and Foundations

Structure Type	Transpower Model	Benchmark Range (NZD)	Midpoint	Source/Notes
Suspension Tower – Single Circuit (350 kV)	Blended with Double Circuit	$150k – $210k	$180k	Based on Transpower standards
Suspension Tower – Double Circuit (350 kV)	Blended with Single Circuit	$240k – $300k	$270k	Based on Transpower standards
International Benchmark – Suspension Tower (500 kV, double circuit)	Not applicable to Transpower	$280k – $350k	$315k	Provided for context only – not part of NZ system
Foundation (per structure)	~$70k	$55k – 110k	$82.5k	Contractor norms

* 500 kV data is included for context only; this is not directly comparable to Transpower's system.

9.2 Conductors

Conductor selection (e.g., duplex ACSR at 220 kV versus quad HTLS at 500 kV) is a critical driver of both cost and long-term performance. Benchmarks drawn from the AEMO TCD 2025 and Hydro-Québec's high-voltage upgrade studies show conductor costs ranging from NZD 0.35m–0.55m per cct-km for 220 kV duplex ACSR, rising to NZD 0.65m–1.0m for 500 kV quad bundles or HTLS. These figures reflect commodity market volatility (aluminium, steel), span lengths, and handling complexity.

Table 22 Conductors

Conductor Type	Transpower Model	Benchmark Range (NZD/km)	Midpoint	Source/Notes
220 kV Duplex ACSR	~$100k	$75k – $110k	$92.5k	AEMO TCD 2025
***350kV Quad Bundle ACSR/HTLS**	~$170k	$140k - $190k	$165k	Interpolated from AEMO TCD 2025, CIGRÉ TB 815, Hydro-Québec
International Benchmark - 500 kV Quad ACSR/HTLS	Not applicable to Transpower	$180k - $240k	$210k	CIGRÉ TB 815, Hydro-Québec

* 350kV is non-standard but is a locally used voltage class in NZ for higher-capacity lines. Therefore, global datasets do not provide 350kV directly. This benchmark is therefore an interpolation of several datasets (both local NZ and global).

9.3 Access & Enabling Works

Access and enabling works can account for up to 20% of new line project costs, particularly in steep or constrained terrain. Transpower's current model uses flat allowances but does not scale adequately with corridor type. International practice (e.g., CIGRÉ TB 852 on Reconductoring and Access Logistics) indicates values of NZD 80k–220k/km for access tracks and NZD 20k–70k per crossing. These are highly sensitive to corridor overlays and the density of transport/utility crossings.

Table 23 Access and Enabling Works

Item	Benchmark Range (NZD)	Driver
Access track upgrades	$80k – 220k/km	Terrain class
Water/road/rail crossings	$20k – 70k each	Corridor density
Clearance rectification	$5k – 15k/span	Route complexity

9.4 Property, Easements & Environmental

Property and environmental factors are a major contributor to delivery risk. While Transpower includes easement costs, other elements such as stakeholder engagement and environmental approvals are understated. Benchmarks from Ofgem's RIIO-2 cost assessment methodology and AEMO's TCD suggest 1–3% of direct costs should be reserved for structured stakeholder engagement, with environmental and permitting typically 0.5–2%.

Table 24 Property, Easement & Environmental

Item	Current Treatment	Benchmark (NZD)	Notes
Easements	Per parcel	$25k – 80k/parcel	Higher peri-urban
Injurious affect	% of direct	$0.05m – 0.25m/km	Corridor dependent
Stakeholder engagement	*Not explicit	1–3% of direct	Critical in sensitive areas
Environmental/permitting	Lump	0.5–2% of direct	Add corridor scaling

* Clear costs cannot be inferred from the model (i.e., direct costs associated with different types of similar assets or asset type segregation is not clear or are not stated).

9.5 Corridor Class Benchmarks

Figure 6 presents benchmark ranges for transmission line costs across key corridor classes (Rural Flat, Rural Moderate, Rural Steep, and Urban Constrained) at 220 kV, 350 kV, and 500 kV. Data has been drawn from international references including CIGRÉ TB 815, AEMO TCD (2025), and Hydro-Québec cost studies.

For 220 kV alignments, rural flat corridors benchmark between 1.3–1.7 NZD m/cct-km, while urban constrained alignments extend to 3.0 NZD m/cct-km due to traffic management, crossings, and property costs. For 500 kV lines, benchmarks rise significantly, with rural moderate corridors ranging 4.5–6.5 NZD m/cct-km (midpoint 6.0 NZD m/cct-km), reflecting increased structure size, higher foundation requirements, and specialist conductor systems.

The inclusion of a 350 kV benchmark class provides a mid-range reference point, reflecting Transpower's actual operating voltage for double-circuit suspension tower configurations. This ensures that portfolio-level analysis does not overstate costs by referencing a notional 500 kV standard when in practice 350 kV is the governing upper-class system in New Zealand.

It is important to note that the earlier 220 kV cost bands presented in Section 7.5 reflect Transpower's own P50 model outputs, which produce relatively narrow ranges of NZD $0.85m–$1.70m per cct-km depending on corridor class. By contrast, the international benchmark data presented in this section (sourced from Hydro-Québec cost studies, CIGRÉ TB 815, and AEMO TCD 2025 datasets) shows materially higher ranges of NZD $1.3m–$3.0m per cct-km for comparable 220 kV corridors. The divergence between these datasets is not an error but rather a deliberate comparison: Transpower's screening models sit ~25–40% below international comparators.

9.6 Demonstrative Case Studies

9.6.1 Worked Scenario

Scenario: The benchmark midpoint for a 100 km 500 kV line is $6.0m/km. Transpower' new line cost model results in a $4.9m/km cost, about 18% variance (below benchmark). Figure 6 presents a worked example for a 30 km, 220 kV double-circuit line across moderate rural terrain. This demonstrates the implications of benchmark ranges against the current Transpower cost model output.

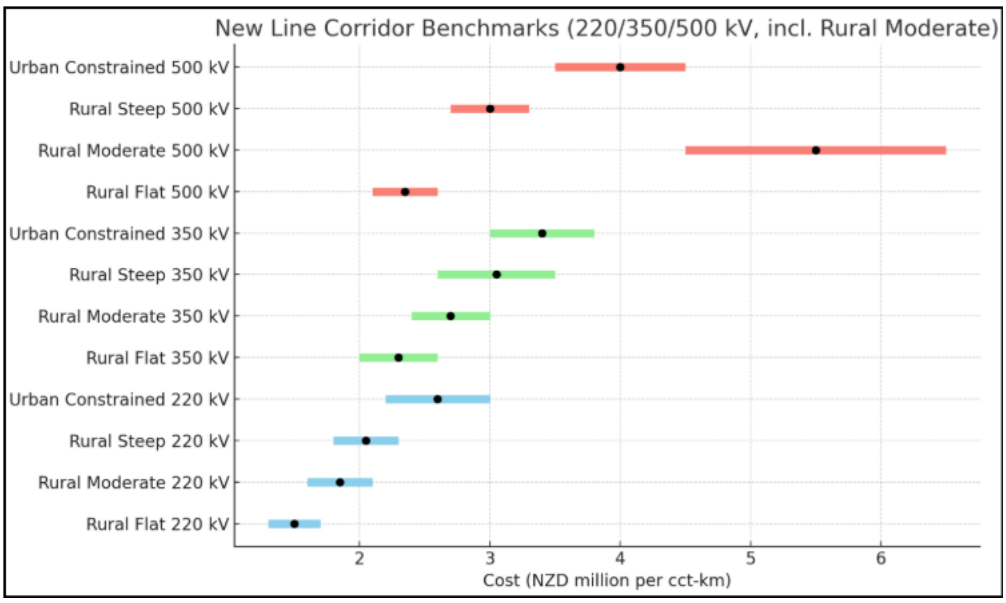


Figure 6: Worked example, new line corridor benchmark costs

9.6.2 Input Assumptions (new line)

The following inputs assumptions were considered for the new line cost split chart show in Figure 7.

- Voltage Class is 220kV double circuit
- Corridor Length is 30km
- Terrain Classification is Rural Moderate (rolling hills, mixed farmland)
- Structure Type is Suspension towers with periodic angle/tension towers
- Conductor is Duplex ACSR (using the benchmarked midpoint per graph above)
- Access Classification as Rural Moderate new access tracks and five crossings

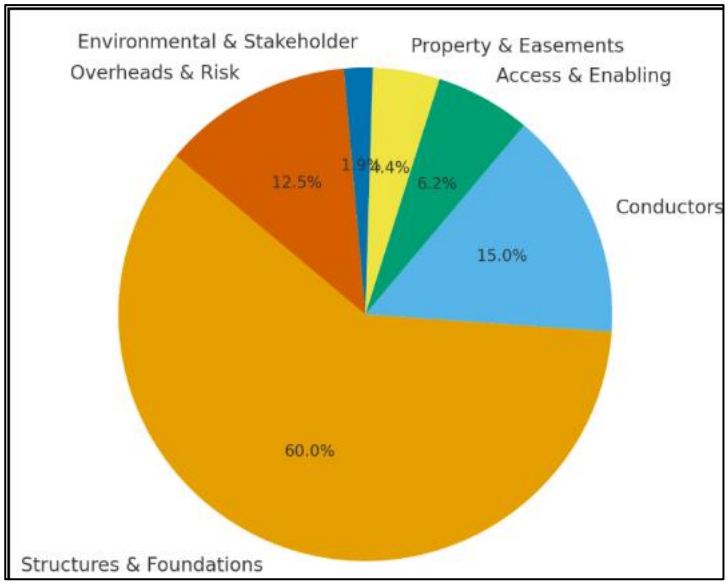


Figure 7: New line cost split chart

9.7 Recommendations

- Differentiate Structure Costs: Move away from averaged unit rates by voltage class; adopt explicit categories (suspension, tension/angle, dead-end) with benchmarked ranges.
- Update Conductor Pricing: Incorporate current market data for aluminium and HTLS conductors, with sensitivity bands to reflect commodity volatility.
- Scale Access Costs: Apply corridor-sensitive scaling factors for access, recognising that steep terrain or constrained corridors can double enabling costs.
- Formalise Property & Environmental: Include explicit cost allowances for stakeholder engagement (1–3% of direct costs) and environmental/permitting (0.5–2%), referencing Ofgem RIIO-2 and AEMO practice.
- Embed Benchmark Checks: Use corridor class benchmarks (220 kV vs 500 kV, rural vs urban) as high-level reasonableness checks at the end of each model run.
- Introduce Worked Example Templates: Provide project teams with plug-and-play worked examples for rapid Class 5 screening estimates, ensuring consistent application.

10 Assumptions and Exclusions

The following assumptions and exclusions apply to work carried out in this report:

- The Class 5 cost classification must be retained in all benchmarking references. This classification is critical to maintaining consistency and clarity in the report.
- Our scope did not include re-costing the project. Instead, our role was to provide guidance on best practices and industry standards for developing cost models.
- All results presented were accurate at the time of writing. However, given the current volatility in industry markets, even minor fluctuations can significantly impact Class 5 estimates due to the broad range between lower and upper bounds.

11 Conclusions

Transpower's current suite of cost models represents a solid foundation, i.e., a set of tools capable of providing indicative estimates. However, as New Zealand's energy transition accelerates, and a much wider end-user pool emerges, the portfolio of cost model current limitations may become key inhibitors of growth. Consideration should be given to building upon the current models in order to evolve them into a platform that is credible, defensible, and future proof.

Our review has enabled us to make several recommendations (refer section 11), that if implemented could see Transpower gain:

- **Strategic Confidence:** A portfolio that remains authentic with its understanding of the local NZ macro environment yet is aligned to international best practice to support multi-billion-dollar investment decisions with integrity.
- **Regulatory Resilience:** Estimates that withstand scrutiny from regulators, stakeholders, and government bodies, backed by transparent benchmarks and consistent methodologies.
- **Delivery Agility:** A unified modelling framework that relays on less user logic and blanket assumptions providing a more agile Class 5 suited to a wider pool of end-users.
- **Investor Assurance:** Cost models that inspire confidence in capital markets, ensuring that investment decisions are supported by defensible and benchmarked analysis.

11.1 Demonstrative Case Studies Summary Table

Table 25 Demonstrative Case Studies

Cost Model	Transpower	Worked Example	Percentage Variance
Cable Cost model	$9,254,661	$12,000,000	23%
HVDC Station Cost Model	$600,000,000	$520,000,000	-15%
Line Upgrade Cost Model	$830,000	$1,000,000	17%
New Transmission Line Cost Model	$4,900,000	$6,000,000	18%
Substation Cost Model	$65,000,000	$82,000,000	21%

11.2 Summary of Recommendations

Our review of Transpower's cost estimation framework spanning the Basis of Estimate (BOE) and all five cost models (substations, cables, HVDC, line upgrades, and new lines), has identified systemic opportunities for improvement. While each model broadly meets the requirements of an AACE Class 5 screening tool, they share several consistent weaknesses that, if addressed, would transform the portfolio from a set of indicative tools into a unified, benchmarked platform capable of supporting strategic decisions with confidence.

Key changes recommended across the portfolio include:

- **Granularity of Inputs:** Move away from reliance on averaged unit rates and introduce differentiated cost categories (e.g., suspension vs. tension towers; GIS vs. AIS substations; cable burial depth options; converter cooling systems).
- **Market-Linked Costing:** Incorporate sensitivity bands tied to commodity indices (aluminium, steel, copper, oil/fuel, shipping) to capture volatility and reduce systemic underestimation risk.
- **Access, Property & Enabling Works:** Standardise treatment of access logistics, easements, injurious affect, stakeholder engagement (1–3% of direct), and environmental approvals (0.5–2%), ensuring they are embedded rather than treated as ad hoc add-ons.
- **Benchmark Integration:** Adopt international benchmark references (AEMO TCD 2025, Ofgem RIIO-2, CIGRÉ technical brochures, Hydro-Québec and US EIA norms) as 'guard rails' for all models, so that outputs are defensibly checked against corridor or asset class ranges.
- **Class 5 Consistency:** Ensure all models consistently apply Class 5 principles (broad ranges, high uncertainty acknowledged), while clearly flagging optional pathways for upgrading to Class 4 or 3 where greater certainty is required.
- **Portfolio Standardisation:** Align methodologies, data structures, and reporting formats across all models to create a coherent portfolio that could potentially plug directly into TEES and support enterprise-level decision making.

This is more than a technical uplift — it is a repositioning to a more strategic decision-support system. It signals Transpower's shift from reactive estimation to proactive investment planning, setting a new benchmark not just in New Zealand, but globally.

To clarify, all of our recommendations are with respect to models that deliver Class 5 outputs for initial project screening purposes. We understand that upon receipt of this report Transpower will consider further the strategic aims / output required of the models, along with the approach and context for releasing the models to wider stakeholders. We would be happy to subsequently refine or expand our recommendations accordingly based on Transpower's feedback.

B. Clarification and Content

Appendix. B – Clarification and Content for Phase -2

The following responses and additional analysis and benchmarking have been provided as an outcome of the clarification discussion between Transpower and Mott MacDonald on the 13 October 2025 and the receipt of the second stage comments register received from Transpower on 10th October. This appendix should be read in conjunction with Report Phase 2 and the Comments Register.

Numbering is aligned with the comments register for ease of use. Additionally, the relevant section of Report 2 has been noted (where applicable). Comments C.1 to C.3, D.1, D.3 to D.6, F.1 to F.3, G.4 to G.8, H.7, I.3 to I.8, J.1 to J.3, J.6 and K.0 have not been included in this appendix as these were noted as *'further context/content not required'* or no comments were provided.

Additional Clarification and Content

Response to General Question 1 – Foreign Exchange

Additional content/context for Section 2 of Report 2

Foreign exchange (FX) conversion was handled at the time of benchmarking using prevailing mid-market rates for the respective currencies. Where benchmarks were taken from international projects, AUD or USD rates were used depending on the original currency, then converted to NZD at the spot rate at the time of analysis (Q2–Q3 2024). We acknowledge that FX rates fluctuate, so the sensitivity range in the benchmark outputs covers minor FX variance (±5 to 7%).

Construction input indices were used primarily from the NZ PPI – Inputs to Industry (Electricity & Gas Supply), IHS indices for Australia and the US, and MBI Engineering Indices for specialized works (substations, HV cable supply). These indices were applied only when escalating older benchmarks to bring them to common year (FY24) values. They were not used as price sources on their own.

Response to General Question 3 – Inclusion Definition

Additional content/context for Section ALL of Report 2

Benchmark costs were treated as **all-inclusive capex** at a Class 5 screening level unless otherwise stated. This includes:

- EPC cost or vendor price (if available),
- Indirect allowances (preliminaries, site establishment, management),
- Risk uplifts (market volatility, location risk),

- Moderate design allowances (if detailed design was unavailable),
- Escalation to FY24 using input indices.

O&M, land acquisition, network access charges, and contingency are **excluded**, unless explicitly noted (e.g., in property benchmarks).

Response to Comment D.2 – MBIE Indices

Additional content/context for Section 4.2 of Report 2

In response to Transpower's request, we have summarised below the specific indices used in Report 2, which are drawn from MBIE's publicly available datasets. These indices reflect 2022–25 cost shifts for civil, electrical installation, and equipment procurement activities and were validated against live market feedback.

Escalation Indices Used

The following escalation indices were applied in the preparation of Report 2 to reflect contemporary market conditions and cost trends relevant to New Zealand transmission infrastructure delivery. The indices are derived from MBIE's Construction Cost Indices (CCI) dataset and focus on flat percentage adjustments suitable for high-level benchmarking and early-phase estimate normalisation. The indices selected correspond to the most representative cost drivers for the scope categories addressed in Report 2, namely:

- Civil construction works
- Electrical works
- HV plant and equipment procurement

Flat escalation factors were applied to 2022–23 base costs to adjust to present-day values (mid-2025), with the rationale and references provided in the table below.

Category	Index Source	Index Applied	Justification / Notes
Civil Construction Works	MBIE – Civil Works Index	6.7%	Reflects aggregate growth in horizontal infrastructure costs 2022–2025.
HV Electrical Installation Works	MBIE – Electrical Index	8.3%	Applied to electrical installation and integration scope; aligned to HV contractor rates.
HV Equipment Procurement	MBIE – Equipment Index	9.8%	Reflects supply chain and shipping volatility affecting transformers, switchgear, etc.

Notes:

- The above indices were calculated as cumulative growth across FY22–FY25 based on quarterly MBIE data.

- These values were cross-checked against selected vendor inputs and remain within the range of live market feedback (±2%).
- Escalation treatment was applied on a category basis, not at a component or task level, to retain benchmarking clarity and prevent artificial precision.

Response to Comment E.1 - BoE Recommendations

Additional content/context for Section 4.4 of Report 2

We support the core recommendation to retain a Class 5-aligned structure and to incorporate new cost categories for staging, consenting, and cyber/auxiliaries.

Regarding escalation: our proposal to allow dual-stream escalation (civil vs electrical) is grounded in MBIE indices, which show diverging trends across commodities. For instance, electrical equipment rose 8–10%, while civils remained below 3% in some periods.

Placeholder values for brownfield staging, consent delays, and risk reserve should be visible in all early-stage estimates and separated from general contingencies. We also support the creation of an Assumptions Register alongside each BoE version. This ensures cost categories that are currently excluded are transparently documented, reducing misinterpretation risks downstream.

Response to Comment F.4 & F.5 - International Benchmarking Comparisons and GIS vs AIS Cost Comparison

Additional content/context for Section 5.3 & 5.4 of Report 2

While transformer costs appear light against global benchmarks, this is likely to reflect volume discounts embedded in recent procurement events. HV GIS pricing, as noted, is particularly sensitive to specification (e.g. indoor vs outdoor, busbar configurations).

The following tables have been developed to illustrate benchmark ranges across brownfield uplift, cybersecurity, fencing, SCADA, and temporary works. This framework can be expanded as future benchmarks are sourced. Additionally we provided detailed benchmarking around brownfield, temporary and staging in Appendix B of Report 1.

The benchmarking below draws upon international cost data from UK RIIO, Australian NSP guidance, and selected project-specific historical references. All percentages are indicative allowances based on total construction cost (TCC), with actuals varying by site constraints, standards, and technical specifications.

Category	Typical Allowance (% of TCC)	Benchmark Justification / Notes
Brownfield Staging Costs	10–15%	CIGRÉ TB 815; includes live site access management, outages, and limited work fronts
Cybersecurity Systems	1–3%	Includes digital protection upgrades, SCADA intrusion protection, and encrypted comms
Fire & Auxiliary Systems	1–2%	Foam/gas suppression, emergency lighting, signage, safety showers
Temporary Works	2–4%	Access tracks, fencing, mobile substations, scaffolding, platform protection
HV Testing & Commissioning	1–2%	Specialist labour and equipment mobilisation, particularly for GIS or HV cable terminations
Earthing & Lightning Protection	1–3%	Site-specific depending on soil resistivity; includes earthing grids, lightning masts
Environmental & Cultural Mitigations	0.5–2%	Noise bunds, fauna fencing, archaeological surveys where applicable

Overview of AIS/GIS Benchmark Comparison

The benchmark comparison below evaluates a typical 220/110 kV substation configuration using both GIS and AIS bays. This is to support Transpower's request to have some understanding around the benchmarking of GIS versus AIS substation configurations in the context of New Zealand project delivery norms.

The scope includes 2×250 MVA transformers and 6 switchgear bays. GIS installations, while compact and resilient to environmental conditions, introduce significant civil and equipment cost uplift.

AIS, more prevalent in NZ (>90%), remains the reference configuration for most recent Transpower builds.

Component	AIS (NZD)	GIS (NZD)	Commentary
Primary Plant (Bays)	4.5M	7.8M	GIS bays priced is based on compact gas-insulated modules.
Civil Works	5.2M	8.0M	GIS requires more intensive civil design and enclosures.
Control & Protection	2.1M	2.4M	Slight uplift for GIS-integrated control interfaces.
Transport & Handling	1.8M	2.6M	GIS modules have higher logistics and handling requirements.
Contingency & Margin	2.5M	3.4M	Assumes 10–15% contingency applied post-estimate.
Total Estimated Cost	16.1M	24.2M	Rounded composite cost based on recent quotes (2024).

The estimated delta between GIS and AIS installations is approximately 50% on direct costs, with major differences driven by equipment and civil complexity. BOE scenarios using GIS without explicit uplift flagging may misrepresent likely NZ build costs unless justified by site or environmental constraints.

Response to Comment F.6 - Request for Definition Clarity & Enhancements

Additional content/context for Section 5.5 of Report 2

The following remarks are in response to item F.6 on Report 2 comments register with a focus on improving granularity, benchmarking accuracy, and alignment with international practices. The items listed are aimed at improving the transparency and flexibility of the cost estimation framework.

Auxiliary Systems Definition

Auxiliaries in the context of substation design include systems such as control and protection panels, DC battery systems, SCADA, HVAC for control rooms, internal building services, lighting, earthing systems, and internal cable trays or ducts. Placeholder values should be carefully benchmarked to avoid potential overlap with civil or secondary work.

Brownfield Staging Cost Adders

Brownfield projects typically attract higher staging and mobilisation costs due to constrained work windows, deconfliction, temporary works, and interface risk. A reasonable allowance for brownfield uplift ranges between 10–15% based on observed

project data across Australia and New Zealand. This may be refined using project-specific inputs.

Benchmarking Enhancements

To improve benchmarking accuracy, the following recommendations are proposed:

- Apply NZ PPI (Producer Price Index) and IHS indices to normalise historical project costs.

Expand building block descriptors to distinguish between:

- Primary plant (e.g., transformer bays, feeder bays, bus couplers)
- Civil works (e.g., earthworks, foundations, control buildings)
- Secondary systems (e.g., protection, metering, comms)
- Auxiliary systems (as described above)

Optional Upgrades and Component-Level Modelling

Component-level modelling is encouraged where data is available, to enable optioneering and modular cost assessment. Probabilistic inputs may be applied to better represent ranges for complex or high-risk works.

Response to Comment G.3- Trenchless Crossings Benchmarking

Additional content/context for Section 6.2 of Report 2

We recognise Transpower's issue with respect to currently not possessing enough route data. However, we do see a growing importance of trenchless methods such as Horizontal Directional Drilling (HDD) and micro tunnelling in urban and environmentally sensitive areas.

Therefore, we recommend that in future iterations of the models, treating trenchless crossings as a conditional modifier or cost driver where HDD is proposed. Applying this at the route engineering level would allow benchmarking without introducing unwarranted complexity across the baseline.

We can also offer further benchmarking data, should Transpower identify a recurring pattern of trenchless deployments (e.g., across wetlands, highways, or rivers). Mott MacDonald has reference data for recent HDD campaigns in Auckland, Victoria, and SE Queensland.

Response to Comment I.1- Line Upgrade

Additional content/context for Section 8 of Report 2

The limitations noted in Transpower's TTU with respect to upgrade scenarios are understood. While uplift modelling for O&M, consenting, and enabling works may be case-specific, we propose building default placeholder percentages based on industry precedents (e.g., Ofgem RIIO-2 and AEMO ISP).

For example, indicative allowances of 1–2% of capex for O&M and 3–5% for consenting/environmental works can be embedded to provide Class 5 coverage. These would be subject to override during detailed cost modelling but would serve as a consistent base in early-stage estimates.

Response to Comment I.2- Reconductoring Benchmarks

Additional content/context for Section 8.1 of Report 2

HTLS options can be added to the benchmark library, including design variations and performance uplift factors. While reconductoring costs may vary depending on the terrain, span lengths, tower strength, and conductor weight, we agree that it is worthwhile to benchmark a range of solutions—particularly for brownfield uprates. We recommend including benchmarks for:

- Conventional aluminium conductors (ACSR, AAAC)
- HTLS types (ACCC, INVAR, GZTACSR)
- Blended solutions (e.g., new conductor + tower upgrades)

Response to Comment I.7- Re-benchmarking for 30km Line

Additional content/context for Section 8.6 of Report 2

We agree that Transpower's internal volume-based data for reconductoring would produce stronger benchmarks. To calibrate against that, we propose that Transpower could:

- Create a reconductoring-specific benchmark range that includes anchor point values for typical 30 km, 60 km, and 100 km lengths
- Identify cost deltas based on terrain and span strengthening
- Include dual benchmarks for like-for-like reconductoring vs. upgrades (e.g., ACSR to HTLS)

Response to Comment J.2- Model Blending Clarification

Additional content/context for Section 9.1 of Report 2

Clarification around model blending (double + single circuit) should be included. We recommend explicitly separating:

- Structures by type (suspension, tension, terminal, etc.)
- Circuits by configuration (D/C vs S/C)
- Foundations by class (pad, pile, rock anchor)

Response to Comment J.7- 500kV Benchmarking

Additional content/context for Section 4.6 of Report 1

We understand that 500 kV infrastructure is not currently part of the New Zealand transmission network, and therefore sits outside the immediate scope of Transpower's

operational planning. However, the inclusion of a 500 kV benchmark in Report 2 was intentional for the following reasons:

Comparative Insight: 500 kV lines and substations are increasingly being adopted in Australia and internationally for major interconnectors and renewable backbone transmission projects. As Transpower evaluates long-term resilience and capacity requirements—particularly under high-demand or decarbonisation scenarios—benchmarking higher-voltage solutions provides a useful upper bound for cost estimation and strategic planning.

Consistency of Methodology: Several cost models and vendor quotes used in the Report 2 analysis reference both 330 kV and 500 kV builds. Including a 500 kV benchmark allows us to validate the curve of cost increase relative to voltage class, particularly for structural and civil cost elements.

Screening Templates: The 500 kV worked example serves as a plug-and-play template to support screening of hypothetical high-capacity transmission options in future investment scenario modelling.

Response to Comment J.8 – Recommendation Clarity

Additional content/context for Section 9.7 of Report 2

Our response to the two comments from Transpower is as below:

Voltage Class Granularity: We support differentiating structure types by span, suspension, tension, etc., but also propose including "weighted default mixes" for fast screening.

Access Scaling: Corridor-sensitive uplifts can be embedded using “terrain tags” (e.g., steep forested, constrained urban, dry rural) for uplifts of +5% to +25%.

Response to Comment K.1 – Granularity of Inputs

Additional content/context for Section 11 of Report 2

Section 11 of Report 2 uses the example of tension vs suspension tower mix to highlight a broader point about variability in tower design assumptions.

The phrase “suspension vs tension” refers to different transmission tower types used to support high-voltage lines. Suspension towers primarily carry the weight of the conductors vertically and are typically used in straight runs, while tension (or strain) towers are designed to withstand horizontal pulling forces, such as at angle points or ends of line sections. Tension towers are more structurally robust and generally more expensive due to their reinforcement requirements.

In Report 2, we were pointing out that even within a common voltage class (e.g., 220 kV

double circuit), estimates can vary depending on the assumed ratio of tension to suspension structures. For example, one benchmark may assume 1 tension tower for every 4 suspension towers (20% tension), while another may assume 1 in 6 (16.7%). This difference, though subtle, can lead to significant cost divergence over a long corridor.

While we acknowledge that suspension vs tension mix is highly project-specific, we included this example because it illustrates the kind of embedded design variation that can make one benchmark look "high" and another look "low." Our recommendation is not to standardise a single assumption, but to make such embedded ratios transparent when building or comparing unit-rate benchmarks.

Response to Comment K.2 – Commodity Risk

Additional content/context for Section 11 of Report 2

Mott MacDonald recognise Transpower's concern, and we agree that forecasting commodity prices beyond a 5-year window introduces high uncertainty. Our recommendation is not to forecast absolute movements, but rather to incorporate current commodity indices (e.g., aluminium, steel, copper, oil/fuel, shipping) at the time of estimating and applying a banded sensitivity analysis to account for volatility.

This can be used to bracket likely cost ranges and inform appropriate risk allowances, particularly for long-lead procurement items like substation steelwork, transformer cores, or conductor materials.

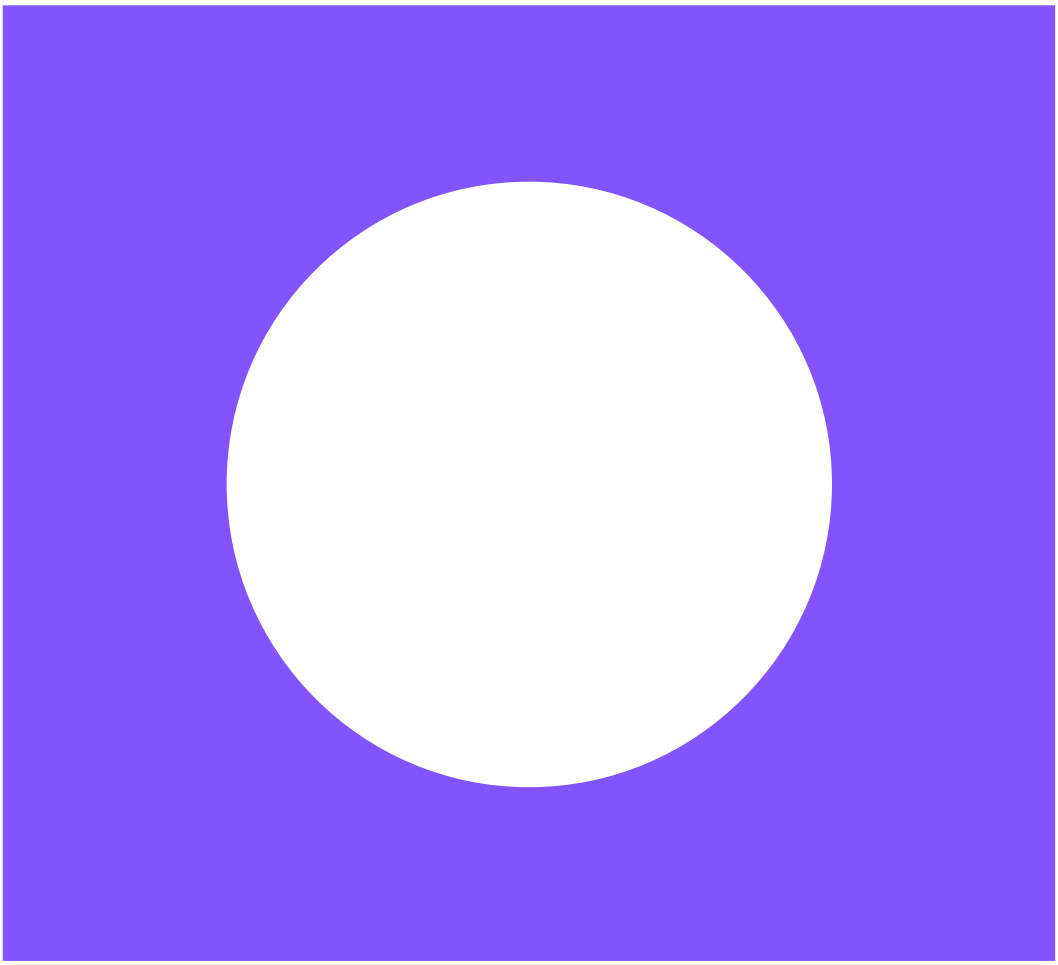
This technique is already applied in regulatory contexts (e.g., Ofgem's indexation method for transmission), and can help reduce the underestimation risk observed in legacy benchmarks that fail to adjust for inflationary shifts in commodities.

Response to Comment K.3 – Context Clarification "Embed"

Additional content/context for Section 11 of Report 2

In this context, "embed" means to systematically build those costs into the core model assumptions, rather than treating them as separate or optional add-ons. For example, access easement acquisition, stakeholder engagement effort, and minor environmental approvals (e.g., cultural heritage or vegetation overlays) should be embedded into standard route unit rates (e.g., $/km) with default percentages (typically 1–3%) that reflect historic averages.

This avoids the risk of these items being excluded or underestimated during early-stage screening, which has been a known contributor to cost uplifts in past NZ transmission projects. The embedded approach also allows for easier calibration against actuals where data exists.



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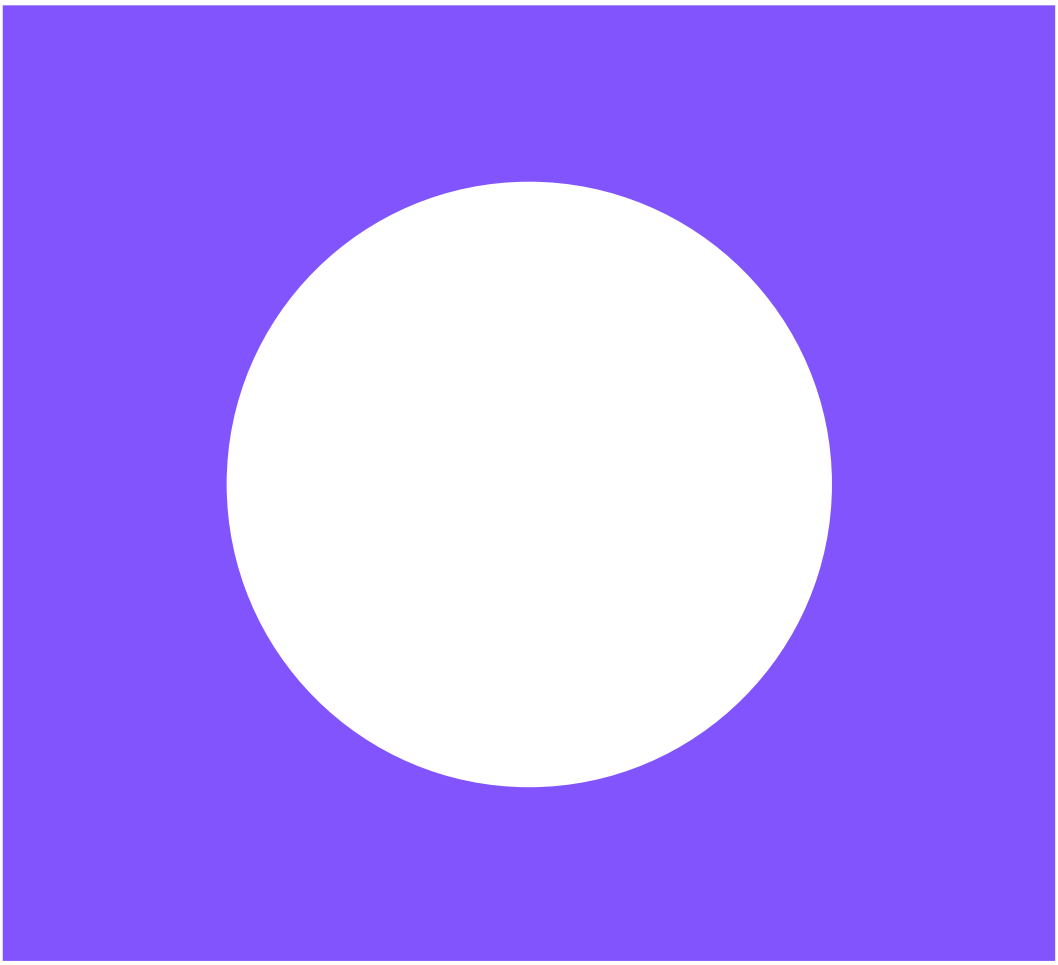

Transpower - Further Development of Class 5 Cost Estimation Models

Phase 3 Report

January 2026

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Transpower - Further Development of Class 5 Cost Estimation Models

Phase 3 Report

January 2026

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Contents

Executive summary 1

1 Introduction and Context 2
1.1 Why this work exists now 2
1.2 Te Kanapū – Future Grid 2
1.3 Phase 3 within Te Kanapū – intent and focus 2
1.4 What emerged from addressing the brief 3
1.5 Emergence of an architectural and horizon-based framework 3
1.5.1 The Escalation Universe 3
1.6 How to read this report 4
1.7 What this report is — and what it is not 4

2 Technologies, Cost and System-Level Implications 6
2.1 HVDC Converter Technologies 6
2.1.1 Why HVDC is examined first 6
2.1.2 Purpose and scope of the HVDC assessment 6
2.1.3 HVDC Technology 6
2.1.4 HVDC technology families 7
2.1.5 Cost structure and New Zealand-specific considerations 7
2.1.6 Transfer capability and performance envelope 7
2.1.7 Behaviour under New Zealand system conditions 8
2.1.8 Relevance across planning horizons 8
2.2 400kV Technologies 9
2.2.1 Why 400 kV substation equipment is examined 9
2.2.2 Purpose and scope of the 400 kV assessment 9
2.2.3 400 kV equipment 9
2.2.4 Limitations of scaling-based cost assumptions 9
2.2.5 Cost structure and primary drivers for 400 kV equipment 10
2.2.6 New Zealand-specific considerations 10
2.2.7 Role of 400 kV infrastructure in long-term planning 10
2.2.8 Relevance across planning horizons 11
2.3 Hybrid Technologies 11
2.3.1 Why hybrid AC/DC architectures are examined 11
2.3.2 Purpose and scope of the hybrid architecture assessment 11
2.3.3 Hybrid and Multi-Terminal HVDC Architectures 11
2.3.4 Conceptual hybrid AC/DC configurations 12
2.3.5 Functional roles of AC and DC within hybrid architectures 12
2.3.6 Cost and complexity considerations 12
2.3.7 Integration and operability considerations 12
2.3.8 Relevance across planning horizons 13

2.3.9 Section 2 Technology Summary 13
2.4 Future Technologies Now (Transformational) 14
2.4.1 Why examine technological choices today to meet energy needs of the future 14
2.4.2 Global Technology Trends Affecting Future Transmission Systems 14
2.4.3 Summary 15

3 Planning Horizons and the Role of International Experience 16
3.1 Why a horizon-based planning framework is applied 16
3.2 The horizon-based framework 16
3.3 Purpose and scope of the horizon-based framework 17
3.4 Definition of planning horizons 17
3.5 Role of international experience 18
3.6 Integrating horizon-based thinking with transmission architecture 18
3.7 Summary 19

4 Cost Realism, Delivery Constraints, and Planning Uncertainty 20
4.1 Why cost realism is addressed explicitly 20
4.2 Purpose and scope of cost realism assessment 20
4.3 Cost, Risk and Deliverability 20
4.4 Structural sources of cost uncertainty 20
4.5 Delivery and constructability constraints 21
4.6 Market and supply-chain considerations 21
4.7 Limitations of point estimates and scaling approaches 21
4.8 Interpreting cost information within this assessment 21
4.9 New Zealand's amplification of risk 22
4.10 Summary 22

5 Comparative Framing of Transmission Options 23
5.1 Purpose of comparative framing 23
5.2 Principles guiding comparison 23
5.3 Comparison dimensions 23
5.4 Comparative positioning of AC, DC, and hybrid options 24
5.5 Influence of planning horizon on comparative outcomes 24
5.6 Role of uncertainty in comparative assessment 24
5.7 Interpreting comparative outputs 25
5.8 Summary 25

6 Cost Escalation, Time Effects, and Long-Horizon Behaviour 26
6.1 Why escalation and time effects are addressed explicitly 26
6.2 Purpose and scope of escalation assessment 26
6.3 Escalation as a structural planning consideration 26
6.4 Limitations of constant-rate escalation assumptions 26

6.5 Interaction between escalation and delivery timing 27
6.6 Differential escalation across technologies 27
6.7 Implications for long-horizon comparison 28
6.8 Summary 28

7 Representing Escalation Behaviour and Long-Horizon Cost Dynamics 29
7.1 Purpose of escalation representation 29
7.2 Escalation as a curve, not a constant 29
7.3 Central, high, and low escalation curves 29
7.4 Role of the central curve in strategic planning 31
7.5 Appropriate use of high and low curves 31
7.6 Interaction between escalation curves and planning horizons 31
7.7 Implications for comparative assessment 31
7.8 Summary 32

8 Worked Examples and Scenario-Based Illustration 33
8.1 Purpose of worked examples 33
8.2 Structure of the illustrative examples 33
8.3 Example 1 — Impact of delivery timing on escalated cost 33
8.4 Example 2 — Sensitivity to escalation curve selection 33
8.5 Example 3 — Effect of staged versus single-phase delivery 34
8.6 Interpretation of example outcomes 34
8.7 Relationship to detailed modelling and future phases 34
8.8 Summary 35

Tables

Table 1-1 Report Structure 4
Table 2-1 Indicative Transfer Capability 8
Table 2-2 400kV Technical Drivers 10
Table 2-3 Conceptual Hybrid AC/DC Architecture 12
Table 2-4 Risks and Interdependencies 13
Table 2-5 Technology Role Summary 13
Table 3-1 The Three-Horizon ‘Technology Adoption’ Model 16
Table 3-2 Planning Horizon Classification 18
Table 4-1 Cost realities for New Zealand 21
Table 5-1 Guidance Principles 23
Table 6-1 Behaviour Differential 27

Figures

Figure 7-1 Three-Horizon Escalation Curve (Illustrative Only) 30
Figure 7-2 Three-Horizon – Central Curve (Illustrative Only) 30

Executive summary

Transpower is entering a period of unprecedented long-horizon uncertainty, driven by accelerating electrification, spatial separation of generation and load, increasing system complexity, and tightening delivery constraints. Decisions made in the near term will have irreversible impacts on cost, flexibility, and system resilience over multiple decades.

This Phase 3 report addresses a central challenge: how to make defensible transmission planning decisions today, in the presence of deep uncertainty about future system form, timing, and technology adoption.

Rather than recommending specific projects or solutions, the report develops a discipline for thinking about timing, technology, and escalation. It focuses on how decisions are framed, sequenced, and stress-tested, rather than what is ultimately built.

The analysis integrates

- Transpower's identified technology categories (400 kV HVAC, HVDC, and future or internationally deployed technologies),
- A Three-Horizon planning model extending to 2060, and
- A structured escalation framework that explicitly links delay, technology maturity, and cost behaviour.

Key Insight - The dominant risk to long-horizon transmission planning is not technology availability, but premature commitment to irreversible decisions under uncertainty.

The report demonstrates that

- Mature technologies such as 400 kV HVAC provide high delivery certainty but limited long-term flexibility.
- Emerging technologies such as VSC HVDC offer enhanced controllability and corridor efficiency at the cost of higher escalation sensitivity and procurement risk.
- Future and internationally deployed technologies inform strategic context but cannot be relied upon for near- or mid-term delivery.

Escalation is treated not as a uniform uplift, but as a behavioural response to delay and uncertainty. The analysis shows that escalation curves differ materially by technology and architecture, with higher-maturity solutions exhibiting shallower escalation profiles and high-capex, supplier-constrained technologies displaying non-linear cost responses to delay.

Planning approach : Align technology choice with planning horizon, preserves optionality where future system needs are uncertain, and avoids early lock-in to high-risk solutions without clear decision triggers.

The main report is intentionally concise. Detailed technology characteristics, cost benchmarks, maturity mapping, architectural comparisons, and worked examples are provided in supporting documents to enable deeper technical interrogation without overloading the core narrative.

Central Outcome: Transpower's ability to deliver an affordable, resilient future grid will depend less on predicting the 'right' technology today, and more on sequencing decisions in a way that preserves flexibility, manages escalation risk, and allows the system to evolve as uncertainty resolves over time.

1 Introduction and Context

1.1 Why this work exists now

New Zealand's transmission system is entering a period where long-term planning decisions carry higher consequence than in previous decades. Decisions taken in the 2025–2060 window will shape network capability, cost exposure, and system resilience well into the middle of the century.

This shift is being driven by several converging factors:

- Rapid growth in inverter-based generation and declining synchronous inertia
- Increased reliance on long-distance power transfers
- Emergence of new generation geographies, including offshore wind potential
- Deep electrification of transport, industry, and data-intensive loads
- Heightened sensitivity to delivery risk, supply-chain constraints, and consenting outcomes

In this context, transmission planning is no longer a linear exercise of identifying a preferred voltage or corridor and applying uniform cost assumptions. Technology choice, system performance, cost behaviour over time, and deliverability are now tightly coupled. Treating these elements independently risks embedding structural bias into long-range planning and obscuring least-regret pathways.

1.2 Te Kanapū – Future Grid

Te Kanapū represents the most significant transmission planning initiative undertaken by New Zealand in recent times.. Its purpose is not simply to compare individual transmission options, but to inform a "*Grid Blueprint*" that remains robust under uncertainty, supports defensible decision-making, and preserves future optionality. This includes considerations for deep electrification, the emergence of new renewable generation geographies, offshore wind potential, and evolving expectations regarding system resilience.

1.3 Phase 3 within Te Kanapū – intent and focus

As part of Te Kanapū, Transpower engaged Mott MacDonald to review and strengthen the cost estimation models underpinning long-term transmission planning.

- **Phase 1** focused on structure and methodology, reviewing the Basis of Estimate and overall cost model architecture (TEES).
- **Phase 2** examined cost completeness and benchmarking, testing model outputs against international references.
- **Phase 3**, which this report represents, moves beyond diagnostics and benchmarking. Its intent is to enable clearer decision-making under long-horizon uncertainty by addressing specific areas of weakness identified in earlier phases and translating those improvements into implementable, TEES-ready outputs.

Transpower's Phase 3 brief requested further development and benchmarking using Class 5-level cost estimation processes across the following four key areas:

1. **HVDC converter stations** – to better understand the applicability, and capacity implications of LCC (Line-Commutated Convertor), VSC (Voltage Sourced Convertor), and emerging HVDC technologies within Aotearoa's evolving system context.

2. **400 kV substation equipment** – to replace simple scaling assumptions with benchmarked, defensible representations aligned with international practice.
3. **International transmission technologies not used locally** – to identify options that may provide future benefit and avoid excluding technologies by default rather than by choice.
4. **Long-term escalation and de-escalation framework** – recognising that escalation assumptions materially influence long-term planning outcomes and cannot be treated as a static input.

Each of these requests addresses a distinct planning risk. Collectively, they reflect Transpower's objective of strengthening not just the accuracy of cost estimates, but the credibility and usefulness of the overall planning process.

1.4 What emerged from addressing the brief

As the Phase 3 brief was addressed across these areas, a consistent insight emerged through two of the key core findings.

Core Findings

- System architecture is more critical than the selection of individual technologies.
- System strength and stability are emerging as the primary limiting constraints.

Individual technologies, cost inputs, or escalation assumptions cannot be meaningfully assessed in isolation over a multi-decade planning horizon. Their relevance, performance, and cost behaviour depend on how they are combined, sequenced, and deployed within the wider system.

This led to a clear distinction between technology selection and system architecture. While the Phase 3 brief was framed around specific technologies and cost inputs, addressing those requests coherently required a higher-order view of how technologies interact within a long-term transmission architecture.

1.5 Emergence of an architectural and horizon-based framework

The analytical framework presented in this report in response to item 4 of Phase 3 was not adopted a priority. It emerged as the simplest structure capable of addressing all elements of the Phase 3 brief consistently.

In particular, the analysis demonstrated the need to differentiate between mature, emerging, and transformational technologies; reflect how cost behaviour changes as technologies mature and global supply chains evolve; avoid discontinuities in long-term cost modelling; and preserve optionality without committing prematurely to unproven solutions.

1.5.1 The Escalation Universe

While the framework has been 'adopted' for primarily transmission technologies within this report, it is important to note that its underlying structure is not technology specific. The same horizon-based logic can be applied to other long-range cost drivers influencing long-term transmission planning — such as labour availability, supply-chain volatility, consenting risk, regulatory change, and construction complexity — with only minor modification to input assumptions. This extensibility is noted for completeness; the focus of Phase 3 remains on technology and escalation as requested by Transpower. However, the broader applicability of the framework provides Transpower with a consistent analytical foundation that may be drawn upon in future planning exercises, should it be useful to do so.

1.6 How to read this report

This report is structured progressively to address the Phase 3 brief while building toward integrated architectural insight:

Table 1-1 Report Structure

Section	Content
Section 1	Introduction & Context (This section)
Section 2	Technologies, Cost and System-Level implications including HVDC, 400 kV infrastructure, Hybrid AC/DC architectures
Section 3	Planning Horizons including Internationally utilised transmission technologies, Three-Horizon technology adoption model
Section 4	Cost realism, deliverability, risk, market constraints
Section 5	Comparative Framing of Transmission Options - Alternative long-term transmission architectures comparison
Section 6-8	Escalation and de-escalation methodology, TEES-ready multipliers framework
Addendums and Supporting Documents: 1. **Technology Report (TRANSPOWER-PH3-REP-002)** 2. **Escalation Report including Horizon (TRANSPOWER-PH3-REP-003)**	These documents are crucial and where relevant each section will refer to a specific supporting document or addendum. This is intentional and aligned with global technical report structures to prevent the report from being too dense. These types of documents hold the broader content, detailed comparisons, reference material, and detailed calculations that have been used within this report or relevant to understand the underlaying concepts.

1.7 What this report is — and what it is not

In order to provide a detailed response to Item 4 of Transpower's Phase 3 brief and ensure it remained context bound, this report utilises the research and results from not only Items 1-3 of the Phase 3 brief but also components of Phase 1 and 2 of this study.

The result was the creation of a multi-dimensional, evidenced-based escalation framework through architectural analysis, by synthesizing all outputs across Phase 1, 2 and 3 with power system physics, deliverability realism, economic and escalation modelling practices, international comparators and New Zealand specific system constraints.

The report provides Transpower with a robust technical and economic framework to support long-term transmission planning. It is intended to improve consistency, transparency, and defensibility within Class 5-level estimation and option evaluation.

It does not prescribe a single build sequence or mandate specific investments. Instead, it clarifies trade-offs, makes implicit assumptions explicit, enables scenario testing, and supports regulator-ready justification of planning decisions.

Where constraints are physical, economic, or mathematical, the analysis is intentionally definitive. Where future outcomes depend on policy, market evolution, or strategic choice, flexibility is preserved.

Due to the multi-dimensional framework, the main body of text and methodology in this report has intentionally been written in a way to avoid overwhelming the reader in technical jargon and computations. Therefore, the heavier weight of technical complexity can be found within the addendums and supporting documents. Where applicable, Sections 1-8 of this report clearly reference the supporting document/s where the technical detail may be found that is relevant to that particular section.

2 Technologies, Cost and System-Level Implications

2.1 HVDC Converter Technologies

2.1.1 Why HVDC is examined first

As New Zealand's transmission system evolves, high-capacity power transfer and system controllability emerge as central planning considerations. HVDC technologies sit at the intersection of these challenges. They are capable of transferring large volumes of power over long distances, while also providing system services that are increasingly relevant in low-inertia, inverter-dominated networks.

For this reason, Transpower's Phase 3 brief requested a deeper examination of HVDC converter technologies, including their cost structure, transfer capability, and applicability to Aotearoa's transmission system. This section responds directly to that request.

HVDC is examined first not because it represents a predetermined solution, but because it anchors several of the long-term uncertainties that Te Kanapū – Future Grid seeks to address. Understanding the range of HVDC options, their respective strengths, and their cost behaviour is a necessary precursor to comparing broader transmission architectures later in this report.

This section is intended to improve option understanding at a Class 5 level. It does not prescribe implementation, optimise system design, or replace detailed power system studies.

Further detail on HVDC technologies can be found within supporting document 'Technologies Today that Create Tomorrow'.

2.1.2 Purpose and scope of the HVDC assessment

The purpose of this section is to provide a comparative assessment of HVDC converter technologies relevant to New Zealand's long-term transmission planning horizon. The assessment focuses on applicability of different HVDC technologies to Aotearoa's system conditions; indicative transfer capacities and functional characteristics; high-level capital cost structure and primary cost drivers; and New Zealand-specific considerations, including seismic design, logistics, and vendor availability.

This assessment is intentionally high-level and aligned with Class 5 estimation principles. No detailed power system modelling or site-specific design optimisation was undertaken. Cost ranges are indicative and intended to support strategic comparison rather than project development.

2.1.3 HVDC Technology

High Voltage Direct Current (HVDC) technology has evolved beyond its original role as a single-purpose transmission solution. As New Zealand anticipates increased penetration of variable renewable energy (VRE), declining synchronous inertia, heightened volatility in load profiles, and greater sensitivity in north–south power transfers, HVDC is poised to become a strategic control layer within the future electricity grid.

For the Te Kanapū project, the evaluation of HVDC solutions must extend beyond simple point-to-point energy transfer, encompassing capabilities for control, stabilisation, and readiness for multi-terminal operation across the 2025–2060 planning horizon.

2.1.4 HVDC technology families

HVDC technologies can be broadly grouped into three families, each with distinct characteristics and planning implications. These are summarised below to provide context for subsequent cost and capability comparisons.

2.1.4.1 Line Commutated Converter (LCC) HVDC

LCC HVDC represents the most mature and widely deployed form of HVDC globally. It is capable of very high-power transfer and has historically delivered cost-effective bulk transmission.

This technology is relevant in contexts where strong synchronous systems exist at both terminals and where controllability requirements are relatively limited. However, its reliance on system strength and reactive power support constrains its applicability in weaker or highly inverter-dominated networks.

2.1.4.2 Voltage Source Converter (VSC) HVDC

VSC HVDC offers enhanced controllability, including independent control of active and reactive power, black-start capability, and operation in weak grid conditions. These features make VSC increasingly relevant as system inertia declines and generation becomes more distributed.

While VSC systems typically exhibit higher unit costs than LCC systems, their functional capabilities can provide system value that is not captured by capacity metrics alone.

2.1.4.3 Hybrid and multi-terminal HVDC configurations

Hybrid and multi-terminal HVDC arrangements combine elements of LCC and VSC technologies or extend HVDC systems beyond simple point-to-point configurations.

These arrangements are of interest in long-term planning contexts were flexibility, staging, or future network integration may be required. Their relevance is closely tied to technology maturity, operational complexity, and system integration considerations.

2.1.5 Cost structure and New Zealand-specific considerations

Across all HVDC technologies, converter stations represent a dominant component of capital cost. Key cost drivers include converter technology selection; power electronics and control systems; reactive power compensation requirements; civil works and seismic design allowances; transport, logistics, and site access constraints; and vendor availability and global supply-chain conditions.

In the New Zealand context, additional considerations apply. These include heightened seismic requirements, limited local experience with certain HVDC configurations, and a relatively small pool of globally active suppliers. As a result, cost ranges for HVDC infrastructure are sensitive not only to technology choice but also to timing and market conditions.

These characteristics are particularly influential in long-horizon planning, where escalation behaviour and supply-chain dynamics can outweigh differences in initial capital cost.

2.1.6 Transfer capability and performance envelope

Indicative transfer capacities for HVDC systems vary by technology type, configuration, and system context. While HVDC is often associated with very high transfer capability, practical limits are shaped by converter design, system integration constraints, and operational objectives.

Table 2-1 Indicative Transfer Capability

Technology	Typical MW Range	Notes
LCC Bipole	700–1,800 MW	Requires robust AC system nodes
VSC Bipole	400–1,500 MW	Expected to reach 2,000 MW by 2035
VSC Monopole	200–700 MW	Suited for regional reinforcement and offshore pilot projects
Multi-Terminal Grid	1,500–3,000 MW system-wide	Represents future meshed HVDC networks

For planning purposes, it is important to distinguish between nominal transfer capacity and overall system contribution. Transfer capability alone does not define system value; controllability, stability support, and resilience characteristics also influence long-term suitability.

2.1.6.1 Environmental Impact

Given New Zealand's limited land availability it may also be of critical consideration to mention the difference in footprint size requirements between these technologies. With VSC technology potentially only needing a third of the space that LCC would require.

2.1.7 Behaviour under New Zealand system conditions

Under New Zealand's evolving system conditions, HVDC technologies exhibit differing strengths.

VSC-based solutions are particularly effective where system strength is limited or where additional controllability is required to support inverter-dominated generation. LCC-based solutions remain effective for bulk transfer in strong grid conditions but require careful consideration of reactive power and fault-level impacts.

Importantly, no HVDC technology resolves all system challenges in isolation. HVDC should be considered as part of an integrated transmission architecture rather than as a standalone solution.

2.1.8 Relevance across planning horizons

The relevance of different HVDC technologies varies across planning horizons. Mature technologies provide near-term certainty but may offer limited flexibility. Emerging configurations offer additional capability but carry greater uncertainty in cost and delivery.

This variation reinforces the need to assess HVDC options within a horizon-based framework, where technology maturity, cost behaviour, and system needs can be considered together rather than independently.

Should Transpower elect to progress to a subsequent phase, the insights from this section could be translated into more detailed cost structures or model assumptions. Within Phase 3, however, the focus remains on enabling informed comparison and strategic clarity.

2.2 400kV Technologies

2.2.1 Why 400 kV substation equipment is examined

As part of New Zealand's future transmission development, the potential role of 400 kV infrastructure represents a material planning question. While Transpower has constructed transmission lines capable of operating at 400 kV, those assets are currently operated at 220 kV, and local experience with 400 kV substation equipment remains limited.

For this reason, Transpower's Phase 3 brief requested specific consideration of 400 kV substation equipment, including its applicability, cost structure, and relevance to long-term planning. This section responds directly to that request.

The intent of this assessment is not to advocate for wholesale adoption of 400 kV infrastructure, but to replace simplified scaling assumptions with a clearer, benchmark-informed understanding of costs, constraints, and practical considerations. This provides a more reliable basis for comparing future transmission options within Te Kanapū – Future Grid.

Further detail on 400kV technologies can be found within supporting document; *Technologies Today that Create Tomorrow'.*

2.2.2 Purpose and scope of the 400 kV assessment

The purpose of this section is to improve understanding of 400 kV substation equipment as a potential component of New Zealand's long-term transmission system.

In line with the Phase 3 scope, the assessment focuses on key items of 400 kV substation equipment relevant to transmission applications; indicative cost structure and primary cost drivers; comparison with 220 kV equipment on a like-for-like functional basis; and New Zealand-specific considerations, including seismic design, logistics, and constructability.

The assessment is intentionally high-level and aligned with Class 5 estimation principles. It does not represent site-specific design, procurement strategy, or detailed optimisation.

2.2.3 400 kV equipment

Globally, countries experiencing rapid electrification, large-scale integration of renewable energy sources, and the need for long-distance power transmission are increasingly adopting 400 kV AC transmission backbones. These systems anchor overall grid strength and provide corridors characterised by high capacity and stability.

For New Zealand, the assessment of 400 kV infrastructure should be oriented towards its strategic role in the future power system architecture. This future may encompass offshore wind generation, substantial renewable energy nodes, large industrial loads, and diminishing levels of synchronous inertia.

2.2.4 Limitations of scaling-based cost assumptions

Historically, indicative costs for 400 kV substation equipment within planning models have often been derived by applying simple scaling factors to 220 kV equipment. While such approaches can provide rapid order-of-magnitude estimates, they risk obscuring important differences in equipment configuration, footprint, and delivery complexity.

Scaling-based assumptions may not adequately capture differences in transformer size, weight, and transport requirements; increased civil works and foundation complexity; higher insulation and clearances affecting layout and land take; supplier availability and manufacturing constraints; and installation and commissioning complexity.

As planning horizons extend and cost sensitivities increase, reliance on simplified scaling factors becomes progressively less reliable.

2.2.5 Cost structure and primary drivers for 400 kV equipment

400 kV substation costs are driven by a combination of equipment, civil works, and integration requirements. Key cost components typically include power transformers (400/220 kV or equivalent); high-voltage switchgear and associated insulation systems; busbar arrangements and support structures; civil works, including foundations, seismic design, and site preparation; and transport and logistics, particularly for large and heavy components.

Table 2-2 400kV Technical Drivers

Feature	Description
Increased Transfer Capability	400 kV lines offer transfer capability approximately 2.0–2.5 times greater than 220 kV lines: well-suited for long north–south transmission corridors and regions with high concentrations of renewable generation
System Strength Enhancement	Establishment of 400 kV nodes increases fault levels, voltage stiffness, and stability margins within the grid
Improved Transient Stability	400 kV infrastructure reduces power-angle sensitivity and enhances oscillation damping, contributing to system robustness
Corridor Optimisation	Single 400 kV double circuit line can replace multiple 220 kV lines; advantageous in areas where community acceptance imposes constraints on transmission development

Compared to 220 kV installations, 400 kV transmission technology generally require greater physical footprint, more substantial civil works, and increased coordination during construction. These factors influence not only capital cost but also programme duration and delivery risk.

2.2.6 New Zealand-specific considerations

In the New Zealand context, several factors influence the applicability and cost of 400 kV substation equipment, including seismic design requirements; transport constraints, particularly for large transformers requiring specialised handling; limited local supply chain, with reliance on international manufacturers; and workforce and installation experience, given limited domestic exposure to 400 kV substation construction.

These considerations do not preclude the use of 400 kV infrastructure, but they do introduce uncertainties that must be accounted for in long-term planning.

2.2.7 Role of 400 kV infrastructure in long-term planning

From a planning perspective, 400 kV infrastructure offers potential advantages in terms of capacity and corridor efficiency. However, these benefits must be weighed against increased complexity, cost sensitivity, and delivery risk.

Importantly, the relevance of 400 kV infrastructure is closely tied to broader transmission architecture decisions. Its suitability depends on how it is combined with other technologies, staged over time, and integrated with existing network assets.

As such, 400 kV equipment should be considered as part of an integrated option set rather than as a standalone upgrade pathway.

2.2.8 Relevance across planning horizons

The applicability of 400 kV substation infrastructure varies across planning horizons.

In the near term, incremental upgrades to existing voltage levels may offer greater certainty and lower delivery risk. Over longer horizons, where transfer requirements increase and corridor constraints intensify, 400 kV infrastructure may become more relevant, provided that cost, constructability, and system integration considerations are addressed.

This reinforces the need to assess 400 kV options within a horizon-based planning framework, where timing, maturity, and system context are considered together rather than in isolation.

2.3 Hybrid Technologies

2.3.1 Why hybrid AC/DC architectures are examined

As transmission requirements increase and system conditions evolve, future network development is unlikely to rely on a single technology in isolation. Instead, a combination of AC and DC infrastructure is expected to play a role in meeting capacity, controllability, and resilience objectives.

For this reason, Transpower's Phase 3 brief requested consideration of hybrid AC/DC transmission architectures. This section responds to that request by examining how AC and DC technologies may be combined, staged, and integrated over time.

The intent of this section is not to define a preferred network architecture, but to explore the characteristics, trade-offs, and planning implications of hybrid approaches. This provides a foundation for later comparison of long-term transmission options.

Further detail on Hybrid technologies can be found within supporting document; Technologies Today that Create Tomorrow'.

2.3.2 Purpose and scope of the hybrid architecture assessment

The purpose of this section is to examine hybrid AC/DC architectures at a conceptual level, focusing on how different technologies interact rather than on the optimisation of individual assets.

In line with the Phase 3 scope, the assessment considers:

- Typical hybrid AC/DC configuration concepts
- Functional roles played by AC and DC elements within a shared network
- High-level cost and complexity considerations
- Integration and operability implications relevant to long-term planning

This assessment is aligned with Class 5 estimation principles and does not represent detailed power system studies or site-specific design.

2.3.3 Hybrid and Multi-Terminal HVDC Architectures

Hybrid and multi-terminal HVDC (MT-HVDC) architectures represent the progression from conventional point-to-point arrangements towards integrated transmission meshes. These advanced architectures facilitate increased controllability, enhanced interconnection, and

improved offshore/onshore integration, while simultaneously reducing dependency on singular AC pathways for system balancing.

2.3.4 Conceptual hybrid AC/DC configurations

Hybrid transmission architectures can take many forms, depending on system needs, geography, and staging strategy. Common conceptual configurations include:

Table 2-3 Conceptual Hybrid AC/DC Architecture

Configuration	Description
DC overlays	Layered onto existing AC backbones to increase transfer capability without duplicating corridors
AC collector systems with DC transmission	AC collector systems feeding into DC transmission for long-distance bulk transfer
Point-to-point DC links	Integrated into predominantly AC networks to relieve constraints or connect remote resources
Multi-terminal or meshed DC segments	Providing flexibility and controllability within broader AC systems

**These configurations are not mutually exclusive and may coexist within a single network over time.*

2.3.5 Functional roles of AC and DC within hybrid architectures

Within hybrid architectures, AC and DC technologies typically perform complementary roles.

AC infrastructure provides network meshing and redundancy, operational familiarity and flexibility, and ease of incremental expansion.

DC infrastructure provides high-capacity bulk transfer, enhanced controllability and power flow management, and improved performance under weak grid conditions.

Understanding how these roles interact is critical to assessing the suitability of hybrid architectures under different system conditions.

2.3.6 Cost and complexity considerations

Hybrid AC/DC architectures introduce both opportunities and challenges from a cost and delivery perspective.

Potential advantages include more efficient use of existing corridors, targeted deployment of high-cost DC assets where their value is highest, and staged investment aligned with demand growth.

However, hybrid approaches also introduce increased system integration complexity, interface and control coordination requirements, higher reliance on advanced protection and control systems, and potential for increased delivery and commissioning risk.

At a planning level, these factors influence not only capital cost but also programme risk and system operability.

2.3.7 Integration and operability considerations

Successful implementation of hybrid AC/DC architectures depends on careful consideration of integration and operability issues.

Key considerations include coordination between AC and DC protection schemes, control system interoperability, operational procedures and workforce capability, and system resilience under contingency conditions.

Table 2-4 Risks and Interdependencies

Risk Category	Key Issue	Implications
Technology	DC protection maturity variable	May necessitate vendor-specific solutions
Vendor Interoperability	Lack of open MT-HVDC standards	Risk of vendor lock-in; limits expandability
Sequencing	Incorrect timing reduces value	Requires coordinated planning of generation and transmission corridors
System Strength	Weak AC nodes require grid-forming capability	Grid-forming MMC required; increases cost but enhances stability
Delivery Risk	Limited OEM competition	CAPEX volatility and extended lead times

These considerations are particularly important where DC assets provide a material proportion of total system transfer capacity.

2.3.8 Relevance across planning horizons

The relevance of hybrid AC/DC architectures evolves across planning horizons.

In the near term, hybrid approaches may be deployed to address specific constraints or incremental capacity needs. Over longer horizons, hybrid architectures may support more transformative network configurations, provided that integration, operability, and cost considerations are managed effectively.

This reinforces the importance of assessing hybrid architectures within a horizon-based planning framework, where timing, maturity, and system readiness are considered together.

2.3.9 Section 2 Technology Summary

Table 2-5 Technology Role Summary

Technology	Primary Role	Key Strengths	Key Constraints	Planning Relevance
HVDC (LCC)	Bulk power transfer	High capacity, mature technology	System strength, reactive support	Efficient long-distance transfer
HVDC (VSC)	Controlled transfer	Weak grid support, flexibility	Higher unit cost	Low-inertia systems
400 kV AC	High-capacity AC	Operational familiarity, meshing	Footprint, civil works	Long-term corridor capacity

2.4 Future Technologies Now (Transformational)

2.4.1 Why examine technological choices today to meet energy needs of the future

The evolution of transmission systems will be driven not by the adoption of a single technology, but by successive waves of innovation that achieve commercial viability at varying points in time. It is neither feasible nor prudent for New Zealand to act as an early adopter of every emerging technology. However, failure to understand and even anticipate the maturation cycle of current and new technologies may result in entrenching the national grid within architectures that are increasingly difficult to adapt beyond the 2035–2060 timeframe.

For this reason, and in correspondence with item 4 of the brief, we have put technological evolvement under the microscope Transpower also requested some consideration (where possible and relevant) of how technologies that are ‘known’ today may behave into the future to become more holistic or viable architectures to use due to their 2060 horizon outlook.

This section responds to that request by noting trends to inform architectural flexibility, not to imply near-term adoption. It is these trends that are already influencing technology choices at a global level today in order to shape the transmission systems of tomorrow.

Further detail on technological evolvement and maturity can be found within supporting document; ‘*Technologies Today that Create Tomorrow’.*

2.4.2 Global Technology Trends Affecting Future Transmission Systems

2.4.2.1 Increasing Reliance on Grid-Forming Converter Technology

Nations with significant inverter-based renewable energy penetration, such as Ireland, Australia, and Germany, are rapidly transitioning towards grid-forming (GFM) High Voltage Direct Current (HVDC) and STATCOM systems to serve as stabilising elements within their electrical grids.

2.4.2.2 Emergence of Hybrid AC/DC Systems as the Backbone Standard

Countries including Denmark, the United Kingdom, Germany, and China are progressing towards meshed hybrid networks, wherein Alternating Current (AC) infrastructure provides system strength and Direct Current (DC) infrastructure delivers enhanced controllability.

2.4.2.3 Offshore Wind Transforming Coastal Network Architecture

The development of offshore wind resources necessitates the establishment of large, multi-gigawatt nodes that often require HVDC collection grids rather than simple radial connections.

2.4.2.4 Compression of Urban Transmission Infrastructure

Urban areas are increasingly utilising technologies such as Gas Insulated Lines (GIL), High Temperature Superconducting (HTS) cables, and Gas Insulated Switchgear (GIS) to address space constraints.

2.4.2.5 Innovations in Seismic Resilience

In regions with high seismic activity, such as Japan, California, and Chile, substations and transmission towers are now engineered with advanced damping systems, pivot footings, and GIS modules featuring low inertial mass.

These international developments closely reflect the constraints currently faced by New Zealand.

2.4.3 Summary

The intent of this section is only to highlight influential trends in the global technology space that may be key drivers in how choices of system architectures are being made to accommodate a forecasted energy future. We cannot predict if a new type of technology may come to market merely suggest that due to certain trends (global energy needs) may predicate how choice of technology use matures and develops over time. This also ties into our later comparison of long-term transmission options and further supports the **'Horizon Cost Framework'**.

3 Planning Horizons and the Role of International Experience

3.1 Why a horizon-based planning framework is applied

Long-term transmission planning is inherently uncertain. Technology maturity, cost behaviour, demand growth, and system conditions evolve over time, often in ways that cannot be predicted with precision at the outset.

For this reason, Transpower's Phase 3 brief requested the application of a long-term-based planning framework that can assist when forecasting both escalation and de-escalation in costs. Furthermore, the framework needs to be proven and in line with global practice and industry benchmarks. This section introduces that framework and explains how it is used to organise the technology and cost considerations discussed in earlier sections.

3.2 The horizon-based framework

With Transpower's timeline reaching well into the future (2060) and taking into consideration the work they have done to date, any TEES integration and potential needs of their Te Kanapu journey a three-horizon cost forecasting model is seen as the most robust and suitable escalation/de-escalation model to use.

The intent of the horizon-based approach is not to forecast a single future network configuration, but to provide a structured way of assessing options under uncertainty.

Aligned with our research and Transpower's current needs we have utilised a **Three-Horizon** approach (see Table 3.2) as a best fit for project. Additionally, and for the purposes of this report we have used the model with **'Technology Adoption'**, as it allows technologies to be considered according to their maturity, deployment risk, and relevance over time, rather than being judged solely on present-day characteristics.

Table 3-1 The Three-Horizon 'Technology Adoption' Model

Horizon	Timeline	Characteristics	NZ Applicability
H1 (Mature) – Commercial Now	2025–2035	Fully proven, replicable, widely deployed	VSC HVDC, 400 kV AC, STATCOM, synchronous condensers
H2 (Emerging) – Advancing / Early Commercial	2035–2045	Demonstration to early commercialisation	Multi-terminal HVDC, offshore HVDC grids, GFM substations, hybrid AC/DC corridors
H3 (Transformational) - Future Technology	2045–2060	Conceptual to demonstration	HTS cables, hydrogen-ready turbines, wide-area HVDC meshing

3.3 Purpose and scope of the horizon-based framework

The purpose of the horizon-based framework is to support strategic planning decisions by distinguishing between:

- Technologies that are deployable with high confidence in the near term
- Technologies that may become viable as conditions evolve and experience grows
- Technologies that remain speculative or transformational in nature

Within Phase 3, the framework is used to organise thinking rather than to assign projects to specific delivery timelines. It provides a lens through which cost behaviour, technology maturity, and system readiness can be considered together.

This framework underpins the comparative assessments presented later in the report and supports consistent treatment of uncertainty across different transmission options.

Further detail on the Three-Horizon Model can be found within the supporting document: *"The Three-Horizon Model Framework".*

3.4 Definition of planning horizons

As highlighted in Table 3-1 The Three-Horizon 'Technology Adoption' Model, underpinning the model and used for the purposes of this assessment, we have kept to three planning horizons. Although these horizons are not tied to specific calendar years or project commitments, they are time bound across the three-horizons as per the principles of Technology Maturity Mapping (see supporting document – The Three-Horizon Model Handbook).

- **Horizon 1 — Established and deployable technologies**

  Horizon 1 encompasses technologies and configurations that are commercially mature, widely deployed internationally, and capable of being delivered with a high degree of confidence under current conditions.

  Characteristics of Horizon 1 technologies typically include established supplier base; well-understood cost structures; proven constructability and operability; and limited reliance on untested integration approaches.

  These technologies form the foundation of near-term planning and provide a reference point for cost realism and delivery certainty.

- **Horizon 2 — Emerging and adaptive technologies**

  Horizon 2 includes technologies that are commercially available but whose application at scale may depend on evolving system needs, operational practices, or accumulated experience.

  Characteristics of Horizon 2 technologies typically include partial or selective international deployment; greater sensitivity to context and integration approach; cost structures that may evolve with learning and scale; and increased delivery and integration risk relative to Horizon 1.

  Horizon 2 technologies are relevant where optionality, staging, and adaptability are important considerations.

- **Horizon 3 — Transformational or speculative concepts**

  Horizon 3 encompasses technologies and configurations that are not yet widely deployed or remain at an early stage of commercial maturity.

These technologies are characterised by limited or pilot-scale deployment; high uncertainty in cost, performance, and delivery; and potential for significant system impact if successfully realised.

Within Phase 3, Horizon 3 technologies are not assessed as discrete options. Instead, their potential influence is acknowledged to ensure that the planning framework remains robust to future change without committing prematurely to unproven solutions.

Table 3-2 Planning Horizon Classification

Horizon	Technology Maturity	Deployment Confidence	Typical Planning Use
Horizon 1	Mature	High	Near-term planning
Horizon 2	Emerging	Moderate	Optionality and staging
Horizon 3	Speculative	Low	Robustness and awareness

3.5 Role of international experience

As previously indicated in section 2.4 of this report – "Future Technologies Now" - International experience provides valuable insight into how transmission technologies perform across different system contexts and stages of maturity. Observing where and how technologies have been deployed helps inform expectations around cost behaviour, delivery risk, and operational complexity.

However, international examples are not treated as direct analogues for New Zealand. Differences in geography, regulation, system size, seismic conditions, and supply chains mean that international experience must be interpreted rather than replicated.

Within this assessment, international experience is used to inform technology maturity classification across horizons; illustrate typical deployment contexts and limitations; and support high-level understanding and benchmarking of cost drivers and sensitivities.

Detailed international case studies and technology comparisons are provided in the supporting documentation referenced earlier in this report.

3.6 Integrating horizon-based thinking with transmission architecture

The horizon-based framework provides a common structure for integrating AC, DC, and hybrid transmission options into a coherent planning narrative.

Rather than selecting a single technology pathway, the framework supports sequencing of investment over time; preservation of optionality under uncertainty; and gradual introduction of more complex technologies as system readiness increases.

This approach allows future transmission architectures to evolve progressively, informed by experience and changing conditions rather than fixed assumptions.

3.7 Summary

The horizon-based framework introduced in this section underpins the assessments that follow. It informs how cost escalation, delivery risk, and system integration considerations are treated in later sections of the report.

By explicitly recognising uncertainty and maturity, the framework provides a disciplined basis for comparing long-term transmission options without overstating precision or prematurely narrowing choices.

4 Cost Realism, Delivery Constraints, and Planning Uncertainty

4.1 Why cost realism is addressed explicitly

As planning horizons extend, uncertainty in cost and delivery outcomes increases. While early-stage estimates can provide useful directional insight, they can also create a false sense of precision if not treated carefully.

For this reason, Transpower's Phase 3 brief requested explicit consideration of cost realism and delivery constraints. This section responds by outlining the factors that materially influence cost outcomes over long timeframes and by setting expectations for how cost information should be interpreted within this assessment.

The intent of this section is not to refine project-level estimates, but to ensure that subsequent comparisons are grounded in realistic assumptions about delivery complexity, market behaviour, and uncertainty.

4.2 Purpose and scope of cost realism assessment

The purpose of this section is to establish a consistent basis for interpreting indicative costs and comparing transmission options under uncertainty.

In line with the Phase 3 scope, this section focuses on structural drivers of cost uncertainty; delivery and constructability constraints relevant to New Zealand; market and supply-chain influences; and limitations of early-stage cost estimates.

This assessment is aligned with Class 5 estimation principles and does not seek to predict final project costs or delivery schedules.

Further detail on cost benchmarking of technologies can be found within supporting document; *Technologies Today that Create Tomorrow'.*

4.3 Cost, Risk and Deliverability

Long-range transmission planning for New Zealand must balance technical performance with practical deliverability. As Te Kanapu transitions from conceptual architecture into implementable pathways, cost realism, construction risk, market constraints, and programme feasibility become just as important as electrical performance.

Around the world, system operators are discovering that future-proofed transmission is not simply a question of "what voltage, what converter, and what corridor," but "can it be delivered on time, within a constrained market, without locking out future decisions?"

4.4 Structural sources of cost uncertainty

Cost uncertainty in long-term transmission planning arises from several structural factors that are not readily resolved through additional analysis at early stages.

These include technology maturity, where newer configurations exhibit less predictable cost behaviour; scale and staging, particularly where investment is phased over multiple decades; interface complexity, including interactions between AC and DC systems; and regulatory and approval pathways, which can affect both timing and scope.

These factors contribute to variability that cannot be eliminated, only managed.

4.5 Delivery and constructability constraints

Delivery constraints play a critical role in determining whether indicative costs can be realised in practice.

In the New Zealand context, relevant constraints include limited availability of specialist construction resources; transport and logistics challenges for large equipment; site access and footprint requirements; and sequencing constraints associated with maintaining system operability.

These constraints influence not only capital cost but also programme risk and contingency requirements.

4.6 Market and supply-chain considerations

Transmission infrastructure relies on a global supply chain for key components, including transformers, power electronics, and specialised switchgear.

Market conditions that influence cost outcomes include concentration of suppliers for high-voltage equipment; manufacturing lead times and production capacity; exposure to currency movements and global demand cycles; and volatility in material and shipping costs.

Over long planning horizons, these factors can materially affect cost outcomes independent of technology choice.

4.7 Limitations of point estimates and scaling approaches

Early-stage cost estimates are often expressed as single-point values or derived through simplified scaling approaches. While useful for screening, such methods can obscure the range of plausible outcomes.

In particular, point estimates do not capture variability or risk; scaling factors may not reflect changes in configuration, footprint, or delivery complexity; and comparisons based solely on nominal cost can be misleading.

Recognising these limitations is essential to avoiding premature conclusions.

4.8 Interpreting cost information within this assessment

Within this report, indicative Class 5 costs are used to inform relative comparison rather than to define absolute values.

Cost information should therefore be interpreted as directional rather than definitive; sensitive to assumptions and context; and subject to variation across planning horizons.

This approach supports transparent comparison while maintaining appropriate caution.

These contextual factors mean total cost ranges for any technological solution must be interpreted through a New Zealand lens, not a European one.

Table 4-1 Cost realities for New Zealand

Impact	Details
Foundation costs	20–40% higher than the global baseline

GIS technology	Performs better in high-seismic zones
Towers in alpine regions	Requires deeper anchoring
Substation ground improvement	Common (e.g., gravel raft, structural fill)
Logistics and handling costs	10-20% higher than the global baseline (can be artefact dependant)

Subsequent sections build on this foundation to compare transmission options in a way that reflects both technical merit and practical deliverability.

4.9 New Zealand's amplification of risk

In a relevant context focussed on New Zealand it is worth noting that as an island nation therefore, requiring long-distance shipping, small batch sizes, and specialist port/road logistics, the country may sit at the back of the global priority queue unless early procurement strategies are adopted.

With global markets experiencing unprecedented demand for transformers, MMC valve stacks and labour specialists, contractors and OEMs often price NZ projects with a premium to account for uncertain logistics windows, remote-site mobilisation, limited subcontractor depth, and the high consequence of delay in islanded grids. The timing impact is discussed further within the technical part of the escalation/de-escalation framework.

4.10 Summary

The considerations outlined in this section underpin the comparative assessments that follow.

By explicitly recognising uncertainty, delivery constraints, and market behaviour, the report avoids overstating confidence in early-stage estimates and provides a more robust basis for long-term planning decisions.

This is primarily in recognising that sometimes international benchmarks can mislead if applied without adjustment. As shown in Table 4-1, in New Zealand's case we often see uplift in civil cost compared to Europe due to seismic anchoring, steep terrain, and geotechnical complexity; 10–20% uplift in logistics cost, especially for large transformers or converter modules requiring port-based handling and bridge strengthening; highly variable consenting cost; and supply chain premium due to distance from manufacturing centres and limited domestic fabrication.

5 Comparative Framing of Transmission Options

5.1 Purpose of comparative framing

As indicated throughout this report, the future configuration of New Zealand's electricity system cannot be determined solely by technological selections. Rather, the core issue is architectural in nature:

"Which long-term backbone architecture delivers the optimal combination of capacity, stability, resilience, deliverability, cost-effectiveness, future optionality, and alignment with New Zealand's structural constraints?"

With previous sections of this report and their supporting documents or addendums having established the characteristics of individual technologies, hybrid architectures, and the sources of cost and delivery uncertainty, this section brings those elements together to enable structured comparison.

The purpose of this section is not to identify a preferred transmission solution. Instead, it provides a consistent framework for comparing transmission options across multiple dimensions, recognising that trade-offs are inherent and context dependent.

This approach supports informed planning discussion by making differences explicit without implying optimisation or selection.

Further detail on transmission technology comparative choice can be found within supporting document; *Technologies Today that Create Tomorrow'.*

5.2 Principles guiding comparison

Comparisons within this assessment are guided by the principles highlighted in figure 9 below:

Table 5-1 Guidance Principles

Attribute	Description
Consistency	Options are considered using a common set of attributes
Context sensitivity	Performance and suitability depend on system conditions and planning horizon
Transparency	Trade-offs are made explicit rather than obscured by aggregation
Proportionality	The level of comparison reflects Class 5 planning intent

These principles ensure that comparison remains informative without overstating precision.

5.3 Comparison dimensions

Transmission options are compared across a set of qualitative dimensions that reflect both technical and practical considerations.

Key dimensions include:

- Transfer capability and functional role
- System controllability and operability
- Cost structure and sensitivity to uncertainty
- Deliverability and constructability
- Flexibility and adaptability over time
- Alignment with planning horizons

No single dimension is treated as determinative. Instead, options are assessed on how they perform across the full set of attributes.

5.4 Comparative positioning of AC, DC, and hybrid options

When viewed through the comparison dimensions above, AC, DC, and hybrid transmission options exhibit distinct profiles.

- **AC-dominant** options tend to offer operational familiarity, network meshing, and incremental expansion capability, but may face limitations in corridor efficiency and long-distance transfer.
- **DC-dominant** options typically provide high transfer capability and controllability, with increased sensitivity to technology maturity, supply-chain constraints, and interface complexity.
- **Hybrid AC/DC** options combine attributes of both, offering flexibility and staging potential at the cost of increased integration and coordination requirements.

These profiles should be interpreted as indicative tendencies rather than fixed categories.

5.5 Influence of planning horizon on comparative outcomes

The relative attractiveness of transmission options varies across planning horizons.

In earlier horizons, options that align with established delivery capability and operational familiarity may offer greater confidence. Over longer horizons, options that preserve flexibility and accommodate evolving system needs may become more relevant, provided that integration and cost uncertainties are managed.

This reinforces the importance of avoiding static comparison and instead considering how option profiles evolve over time.

5.6 Role of uncertainty in comparative assessment

Uncertainty plays a central role in long-term comparison.

Rather than attempting to eliminate uncertainty, this assessment incorporates it explicitly by:

- Recognising variability in cost and delivery outcomes
- Avoiding reliance on single-point estimates
- Considering sensitivity to market and supply-chain conditions

Options that perform well under a range of plausible futures may offer greater robustness, even if they do not appear optimal under a single assumed scenario.

5.7 Interpreting comparative outputs

Comparative outputs from this section are intended to support structured discussion rather than decision closure.

They should be read as:

- Highlighting trade-offs, not rankings
- Informing sequencing and optionality considerations
- Supporting transparency in long-term planning dialogue

Subsequent sections build on this framing by examining how cost escalation and time-based effects further influence comparative outcomes.

5.8 Summary

While comparative framing provides clarity on relative attributes, it does not yet account for how costs evolve over time.

The following sections extend this comparison by introducing escalation behaviour and time-based effects, allowing the interaction between technology choice, delivery timing, and long-term cost outcomes to be examined in a consistent manner.

6 Cost Escalation, Time Effects, and Long-Horizon Behaviour

6.1 Why escalation and time effects are addressed explicitly

Over long planning horizons, the interaction between cost escalation and delivery timing can have a greater influence on outcomes than differences in initial capital cost. Technologies that appear cost-competitive at a single point in time may diverge materially once escalation, staging, and delivery duration are considered.

For this reason, Transpower's Phase 3 brief requested explicit consideration of escalation behaviour and time-based effects. This section responds by examining how costs evolve over time and how those dynamics influence long-term comparison of transmission options.

The intent of this section is not to forecast prices, but to establish a defensible way of thinking about escalation and time within strategic planning.

6.2 Purpose and scope of escalation assessment

The purpose of this section is to introduce escalation as a structural component of long-horizon planning, rather than as a simple adjustment applied to static estimates.

In line with the Phase 3 scope, this section focuses on:

- The nature of escalation in transmission infrastructure
- Differences between short-term price movement and long-term cost behaviour
- The interaction between escalation, staging, and delivery timing
- Implications for comparing transmission options across horizons

This assessment remains aligned with Class 5 principles and does not seek to predict future market prices.

6.3 Escalation as a structural planning consideration

Escalation in transmission infrastructure arises from multiple interacting drivers, including:

- Labour market conditions and productivity trends
- Material and manufacturing cost trajectories
- Supply-chain capacity and global demand cycles
- Regulatory, environmental, and social requirements

Over extended periods, these drivers do not act uniformly or linearly. As a result, escalation should be treated as a behavioural characteristic of infrastructure delivery rather than a fixed annual percentage.

6.4 Limitations of constant-rate escalation assumptions

Traditional planning approaches often apply a single escalation rate across all costs and time periods. While simple to implement, such approaches can misrepresent how costs actually evolve.

In particular:

- Different cost components escalate at different rates
- Periods of rapid escalation may be followed by stabilisation
- Step changes can occur due to market or policy shifts

Reliance on constant-rate escalation risks overstating confidence and understating variability, particularly for options delivered later in the planning horizon.

6.5 Interaction between escalation and delivery timing

Delivery timing plays a critical role in determining the effect of escalation on total cost.

Options that require:

- Longer development periods
- Extended construction durations
- Later commencement dates

are more exposed to escalation effects than options delivered earlier or staged incrementally.

As a result, comparisons based solely on base-year estimates can be misleading when delivery timing differs materially between options.

6.6 Differential escalation across technologies

Different transmission technologies exhibit varying sensitivity to escalation due to differences in cost structure.

For example:

- Technologies with high labour content may be more sensitive to workforce constraints
- Technologies reliant on specialised equipment may be more exposed to supply-chain volatility
- Complex integration requirements can amplify escalation through extended delivery periods

Table 6-1 Behaviour Differential

Horizon Model	Category	Item	Behaviour/Change
H1	Benchmark Behaviour	Steel	+15–30%
H1	Benchmark Behaviour	Aluminium	+10–20%
H1	Benchmark Behaviour	Shipping	4–5× spikes
H1	Benchmark Behaviour	Labour	+20–40%
H1	Benchmark Behaviour	*FX volatility impacting HVDC + transformer costs	8-15% movement relative to USD/EUR
H2	Learning Curve Behaviour	HVDC VSC	2–6% annual reduction

H2	Learning Curve Behaviour	GIS	1–3% annual reduction
H2	Learning Curve Behaviour	STATCOM/SVC	1–2% reduction
H2	Learning Curve Behaviour	Digital substations	3–8% reduction
H3	Macro Drift Behaviour	Long-term inflation	2–3% p.a.
H3	Macro Drift Behaviour	Construction drift	1–2% above CPI
H3	Macro Drift Behaviour	Geopolitical uncertainty margin	+1%

*The FX impact is 'real-time' mechanics and therefore needs to be reviewed frequently or prior to undertaking a cost model forecast. For clarity the range used in this table is grounded by the following: **1)** NZD/USD swings seen across 2020-2024, **2)** OEM contract exposure where 60-90% of converter and transformer cost is denominated, and **3)** Historical HVDC & transformer procurement tenders.

These differences reinforce the need to consider escalation behaviour alongside technology choice.

6.7 Implications for long-horizon comparison

When escalation and time effects are incorporated, the relative position of transmission options may change.

Options that appear cost-competitive in base-year terms may become less favourable once delayed delivery and cumulative escalation are considered. Conversely, options with higher upfront costs but earlier or staged delivery may exhibit greater long-term robustness.

This does not imply that one class of technology is inherently superior. Rather, it highlights the importance of integrating time into comparative assessment.

6.8 Summary

This section establishes the conceptual basis for considering escalation and time effects. The following sections build on this foundation by introducing structured approaches to representing escalation behaviour and examining how different assumptions influence comparative outcomes.

Together, these sections allow the interaction between technology choice, delivery timing, and long-term cost behaviour to be explored in a transparent and disciplined manner.

7 Representing Escalation Behaviour and Long-Horizon Cost Dynamics

7.1 Purpose of escalation representation

Having established the importance of escalation and time effects in long-horizon planning, this section introduces structured approaches to representing escalation behaviour in a way that supports meaningful comparison.

The purpose of this section is to explain how escalation can be represented analytically without overstating precision, and why certain representations are more appropriate than others for strategic planning.

This section does not prescribe a single escalation pathway. Instead, it presents a framework for understanding escalation dynamics and for testing sensitivity to key assumptions.

Further detail on the Three-Horizon Model can be found within the supporting document: *"The Three-Horizon Model Framework".*

7.2 Escalation as a curve, not a constant

Escalation in long-term infrastructure delivery does not behave as a constant linear function. While constant-rate escalation can be convenient, it fails to capture the compounding and non-linear effects observed over extended planning horizons.

In practice, escalation behaviour is better represented as a curve reflecting periods of accelerated cost growth, periods of relative stability, and structural shifts driven by market, policy, or supply-chain change.

Representing escalation as a curve allows these dynamics to be acknowledged without requiring prediction of specific future events. This is particularly relevant for transmission infrastructure where procurement concentration, consenting duration, and supply-chain maturity vary over time.

7.3 Central, high, and low escalation curves

To support structured comparison under uncertainty, escalation behaviour can be represented using a set of bounding curves rather than a single trajectory.

- **The central curve** represents a most-likely escalation pathway based on observed long-term behaviour and current market understanding.
- **The high curve** represents outcomes where compounding escalation effects are amplified by sustained market pressure, delivery delay, or structural disruption.
- **The low curve** represents outcomes where escalation moderates due to stabilisation, productivity gains, or favourable market conditions.

These curves are not forecasts. They are analytical constructs designed to bound plausible outcomes and to support sensitivity testing.

Figure 7-1 Three-Horizon Escalation Curve (Illustrative Only)

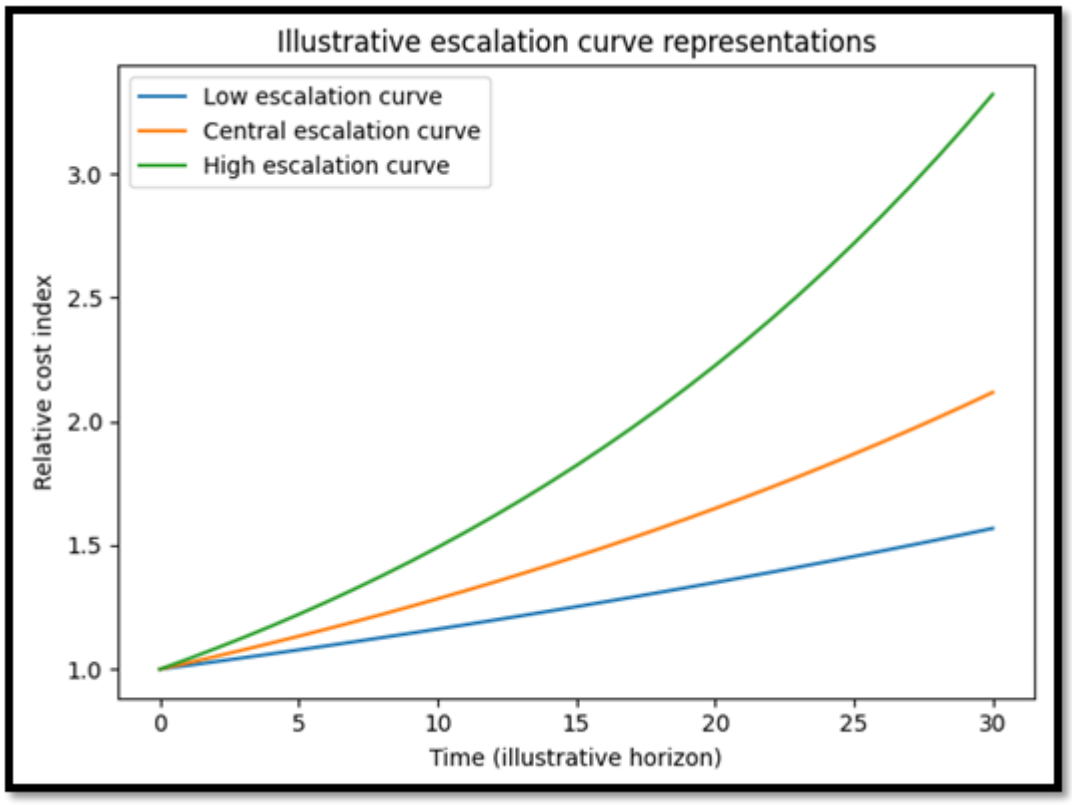
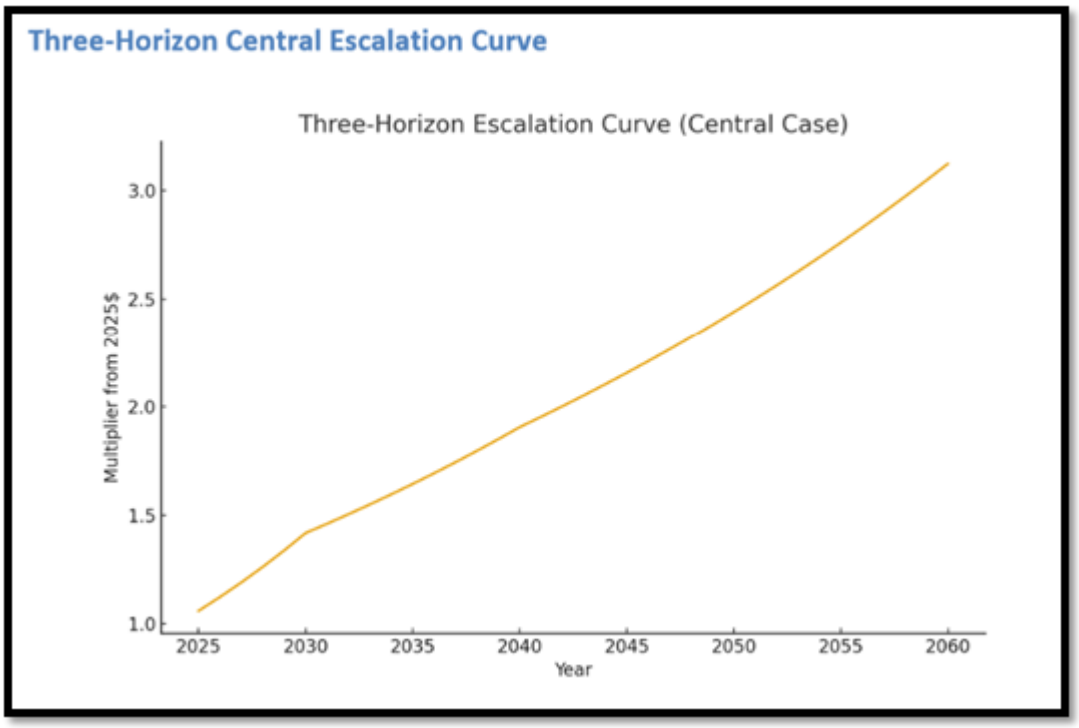


Figure 7-2 Three-Horizon – Central Curve (Illustrative Only)



The curves shown in Figure 7-1 **and** Figure 7-2 **are indicative only and are intended to illustrate the conceptual difference between low, central, and high escalation trajectories.**

Quantitative application of escalation behaviour is demonstrated separately in the relevant supporting documentation.

7.4 Role of the central curve in strategic planning

The central escalation curve plays a distinct role in strategic planning.

Rather than representing a guaranteed outcome, it provides a reference trajectory against which options can be compared consistently. It allows the relative influence of timing, staging, and delivery duration to be examined without biasing analysis toward either optimism or pessimism.

Importantly, the central curve should not be interpreted as an average of high and low outcomes. It reflects a robust planning assumption grounded in observed behaviour rather than statistical symmetry.

7.5 Appropriate use of high and low curves

High and low escalation curves serve a different purpose to the central curve.

They are not intended to be applied indiscriminately to all options or used to inflate contingency allowances. Instead, they are used to explore sensitivity where specific drivers justify their application.

For example, options heavily exposed to global supply-chain constraints may warrant testing against higher escalation trajectories, while options with staged delivery or lower exposure to constrained inputs may exhibit reduced escalation sensitivity.

Misuse of high or low curves can obscure meaningful differences rather than illuminate them.

7.6 Interaction between escalation curves and planning horizons

Escalation curves interact strongly with planning horizons.

Over short horizons, differences between curves may be relatively modest. Over longer horizons, compounding effects can lead to significant divergence, even where initial cost differences are small.

This interaction reinforces the importance of aligning escalation assumptions with both delivery timing and technology maturity.

7.7 Implications for comparative assessment

When escalation is represented using curves rather than constants, comparative outcomes can change materially.

Options that appear favourable under base-year or constant-rate assumptions may perform less well once compounding, delivery timing, and escalation exposure are incorporated. Conversely, options with higher initial costs but shorter delivery timelines or staged implementation may demonstrate greater long-term robustness.

This does not imply that one escalation curve is correct. Rather, it highlights the importance of transparency in how escalation assumptions influence comparison.

7.8 Summary

This section establishes the conceptual and analytical framework for representing escalation behaviour. The following section applies this framework through worked examples and scenario testing to illustrate how different assumptions influence long-horizon outcomes.

Together, these sections bridge the gap between strategic framing and quantitative insight, while maintaining appropriate discipline around uncertainty.

8 Worked Examples and Scenario-Based Illustration

8.1 Purpose of worked examples

The purpose of this section is to illustrate how the escalation representation framework described can be applied in practice to support long-horizon comparison.

Further detail on the Three-Horizon Model can be found within the supporting document: *"The Three-Horizon Model Framework".*

These examples are not intended to predict outcomes or to represent detailed project-level estimates. Instead, they demonstrate how different assumptions regarding escalation behaviour, delivery timing, and staging can materially influence comparative outcomes.

The examples are intentionally simplified to preserve transparency and to focus attention on the drivers of difference rather than on numerical precision.

8.2 Structure of the illustrative examples

The worked examples presented in this section share a common structure:

- A base-year indicative cost
- An assumed delivery timeline aligned with a planning horizon
- Application of central, high, and low escalation curves
- Comparison of cumulative cost outcomes over time

This structure allows differences between options to be explored consistently while maintaining alignment with Class 5 planning intent.

8.3 Example 1 — Impact of delivery timing on escalated cost

This example illustrates the influence of delivery timing on cumulative cost under a common escalation framework.

Two transmission options with similar base-year indicative costs are considered. One option is assumed to be delivered earlier, while the other commences later due to longer development and construction lead times.

When escalation is applied using a central curve:

- The later-delivered option experiences materially higher cumulative cost
- The difference arises primarily from exposure to additional years of escalation rather than from differences in base cost

This demonstrates how delivery timing can outweigh initial cost differences in long-horizon planning.

8.4 Example 2 — Sensitivity to escalation curve selection

This example examines how comparative outcomes vary when different escalation curves are applied.

Using a common delivery timeline, indicative costs are escalated under:

- A central curve
- A high curve
- A low curve

The results show:

- Modest divergence over short horizons
- Increasing divergence over longer horizons due to compounding effects

Importantly, the relative position of options may change depending on the escalation curve applied, reinforcing the need for sensitivity testing rather than reliance on a single assumed pathway.

8.5 Example 3 — Effect of staged versus single-phase delivery

This example explores the impact of delivery strategy on escalation exposure.

Two options are compared:

- A single-phase delivery with later completion
- A staged delivery approach with earlier partial capacity

Under equivalent escalation assumptions:

- The staged option reduces exposure to long-term escalation
- Early delivery of partial capacity moderates cumulative cost growth

This illustrates how staging can influence long-horizon outcomes even where total scope and base costs are similar.

8.6 Interpretation of example outcomes

The worked examples highlight several consistent themes:

- Delivery timing materially influences escalated cost outcomes
- Escalation assumptions interact strongly with planning horizon
- Staging can reduce escalation exposure without altering total scope
- Single-point estimates can obscure meaningful differences

These observations reinforce the importance of integrating time and escalation explicitly into comparative assessment.

8.7 Relationship to detailed modelling and future phases

The examples presented in this section are illustrative rather than exhaustive.

In future phases, similar logic could be embedded within more detailed cost models, allowing:

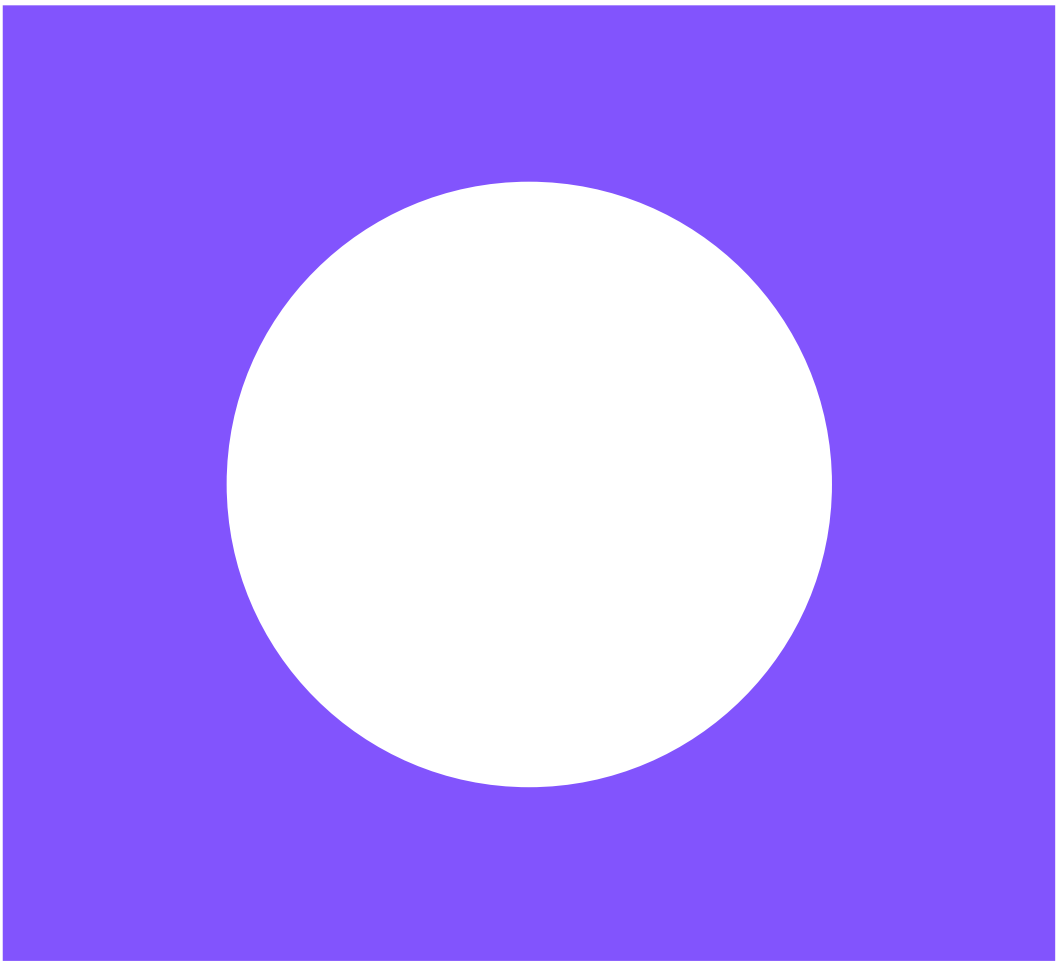
- Parameterisation of escalation behaviour using updated benchmark inputs
- Technology-specific cost structure representation
- Integration with programme and risk models

The conceptual framework established here provides a robust foundation for such development without constraining future implementation choices.

8.8 Summary

This section demonstrates how structured escalation representation and scenario-based illustration can support more robust long-horizon comparison of transmission options.

By focusing on behaviour and interaction rather than prediction, the approach avoids false precision while still providing meaningful insight into cost dynamics.



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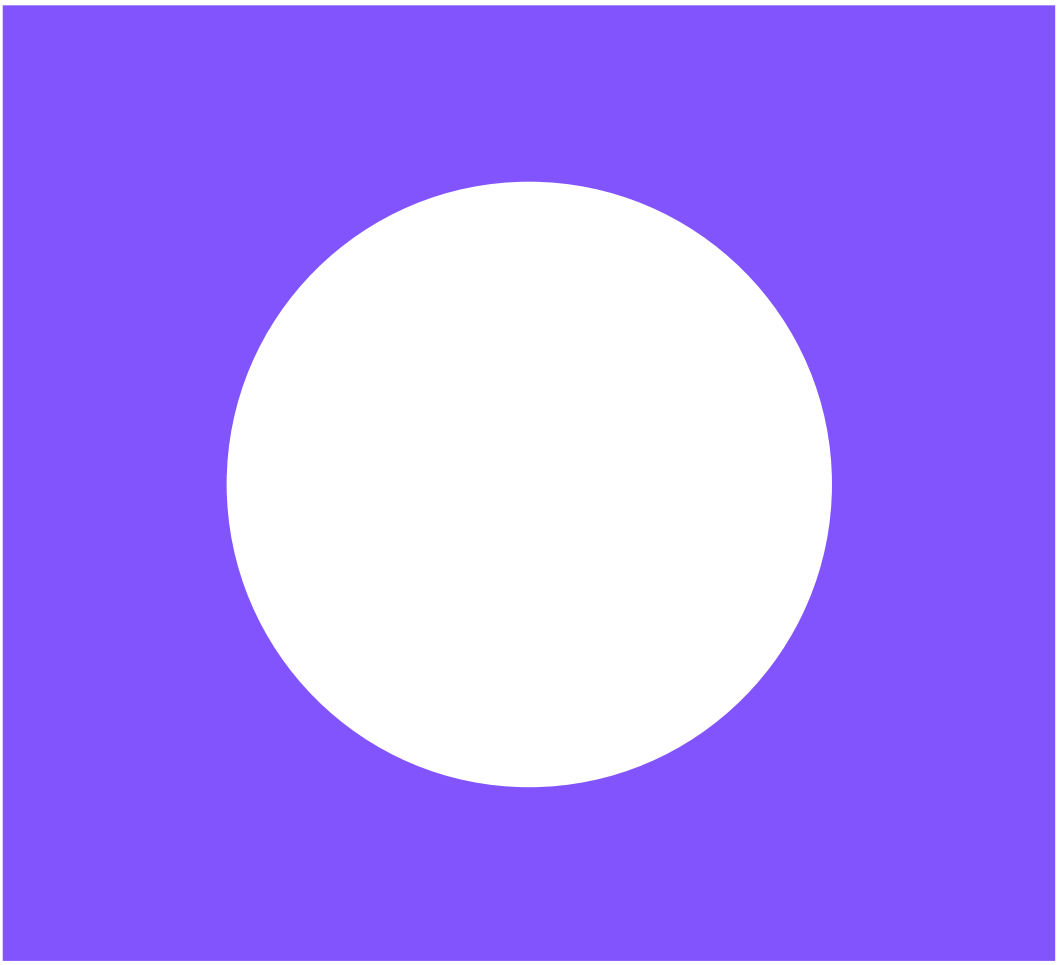

Transpower - Further Development of Class 5 Cost Estimation Models (Phase 3)

Technologies Today That are Creating the Transmission Infrastructure of Tomorrow

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Technologies Today That are Creating the Transmission Infrastructure of Tomorrow

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Contents

Executive summary 1

1 Introduction 2
1.1 Purpose and Scope 2
1.2 Framing the Technology Landscape 2

2 HVDC Transmission Technologies 4
2.1 HVDC Technology Families 4
2.1.1 Line-Commutated Converters (LCC) HVDC 4
2.1.2 Voltage Source Converters (VSC) HVDC 4
2.1.3 Hybrid LCC–VSC Architectures and Multi-Terminal Systems 5
2.2 Functional Role of HVDC in the Transmission System 5
2.3 Suitability Considerations for New Zealand 6
2.4 Summary of HVDC Implications 6

3 400kV Transmission Technologies 7
3.1 Functional Role of 400kV Infrastructure 7
3.2 Comparison with Existing HVAC Infrastructure 7
3.3 Substation and Equipment Considerations 7
3.4 Planning Implications for New Zealand 8
3.5 Summary of 400kV Implications 8

4 Hybrid AC/DC Technology Architecture 9
4.1 Rationale for Hybrid Architectures 9
4.2 Common Hybrid Architecture Forms 9
4.3 Integration and Operational Considerations 9
4.4 Delivery and Escalation Implications 10
4.5 Summary of Hybrid Architecture Implications 10

5 International and Future Transmission Technologies 11
5.1 Purpose of Considering Future and International Technologies 11
5.2 Categories of Future and International Technologies 11
5.2.1 Advanced HVDC configurations 11
5.2.2 Grid-forming and advanced power electronic technologies 11
5.2.3 Advanced conductors and structural technologies 12
5.2.4 Digital and system/artificial intelligence technologies 12
5.3 Maturity and Deployment Considerations 12
5.4 Relevance to New Zealand Planning 12
5.5 Summary of Future Technology Implications 12

6 Technology Maturity Mapping and Temporal Readiness 14
6.1 Purpose of Maturity Mapping 14
6.2 Maturity as a Planning Consideration 14
6.3 Relevant Maturity of Transmission Technologies 14
6.4 Long-Horizon Maturity Mapping 15
6.5 Implications for Subsequent Analysis 16

7 Cost Benchmarking and Comparative Behaviour 17
7.1 Benchmarking Approach 17
7.1.1 Overhead Transmission Line 17
7.1.2 Substation and Converter Station Cost Benchmark 18
7.1.3 Dominant cost drivers by technology 18
7.1.4 Escalation sensitivity by architecture 19
7.1.5 Cost versus delivered capability 19
7.2 Implications for Escalation Modelling 19

8 Integrating Technology, Maturity, Architecture and Cost 20
8.1 Technology Choice as a System Decision 20
8.2 Interaction Between Maturity and Cost Behaviour 20
8.3 Architecture as a Risk Management Tool 20
8.4 Architecture as the Integrating Mechanism 21
8.5 Managing Escalation Through Sequencing 22
8.6 Implications for Long-Horizon Planning 22

9 Horizon-Based Framing and Implications for Decision-Making 23
9.1 Introduction of the horizon-based framework 23
9.2 Summary of technology positioning by horizon 23
9.3 Role of architecture within the horizon framework 24
9.4 Relationship to cost and escalation behaviour 24
9.5 Relationship to the Horizon Model supporting document 24
9.6 Closing summary 24

Addendum 1. 'Other' Technologies 26
AD1.1 HTLS Conductors (High-Temperature Low-Sag) 26
AD1.2 Dynamic Line Rating (DLR) 26
AD1.3 Gas-Insulated Lines (GIL) 27
AD1.4 Multi-Terminal HVDC 27
AD1.5 Hybrid AC/DC Reinforcement 27
AD1.6 Phase-Shifting Transformers (PSTs) 28
AD1.7 Advanced Power Flow Controllers (APFCs) 28
AD1.8 SF_6-Free GIS 28
AD1.9 Digital Substations 28
AD1.10 AI-Based Stability Orchestration and Load Management 29

AD1.11 Nationwide Demand-Management Platforms 29
AD1.12 Compact Towers 29
AD1.13 Cost Benchmarking 29
AD1.14 Detailed Breakdown 31
AD1.15 Risk and Reward Maps 33

Addendum 2. Expanded Architecture Detail and Scoring Matrix 36

AD2.1 Architectural Comparison 36
AD2.2 Architecture 1 — AC-Dominant Backbone 36
AD2.3 Architecture 2 — DC-Dominant Backbone 37
AD2.4 Architecture 3 — Evolutionary AC Reinforcement (220 kV Focused) 37
AD2.5 Architecture 4 — Hybrid AC/DC Backbone (Recommended) 38
AD2.6 Technical Analysis Results 38
AD2.6.1 Expanded Scoring Matrix 38
AD2.6.2 Expanded Justifications 39
AD2.6.3 Stability 39
AD2.6.4 Resilience 39
AD2.6.5 Deliverability 39
AD2.6.6 Cost Efficiency 40
AD2.6.7 Optionality & Future Proofing 40

Tables

Table 7.1-1 Overhead Transmission Line Cost Benchmarks (NZD, real, Class 5) 17
Table 7.1-2 Terminal Asset Cost Ranges 18
Table 7.1-3 Cost Driver Sensitivity by Technology 18
Table 7.1-4 Architecture-Level Escalation Exposure 19
Table 7.1-5 Indicative Cost vs Capability Comparison 19

Figures

Figure 6-1 Technology Maturity Mapping 16
Figure 8-1 Comparative Architecture Scoring 21

Figures

Table AD.1-1 Further cost benchmarking 30
Table AD.1-2 Benefits and Risks Breakdown 31
Table AD.1-3 Benefits heatmap (Reward) 34
Table AD.1-4 Risks heatmap (Challenges) 34
Table AD.2-1 Expanded Scoring Matrix 38
Table AD.2-2 Expanded Justifications 39
Table AD.2-3 Stability 39
Table AD.2-4 Resilience 39
Table AD.2-5 Deliverability 39

Table AD.2-6 Cost Efficiency 40
Table AD.2-7 Optionality & Future Proofing 40

Figures

Figure AD.1-1 ACSR vs Various HTLS Comparison 26
Figure AD.1-2 Key Global GIL Installations 27
Figure AD.1-3 T-pylons used in the UK 29

Executive summary

This Technology Supporting Document provides the detailed technical, architectural, and cost evidence underpinning the transmission technology considerations presented in Transpower's Phase 3 main report.

The purpose of this document is not to recommend specific projects or prescribe immediate investments, but to establish a robust, auditable foundation for understanding how different transmission technologies behave over long planning horizons when assessed in terms of capability, maturity, delivery confidence, architectural role, and cost escalation exposure.

Consistent with Transpower's Phase 3 brief, the analysis focuses on three principal technology groupings:

- High Voltage Direct Current (HVDC) transmission technologies,
- 400 kV High Voltage Alternating Current (HVAC) transmission systems,
- International and emerging transmission technologies not yet deployed within New Zealand.

Key Insights

- Transmission technologies cannot be meaningfully compared on capability alone. Technologies with similar technical performance often exhibit materially different behaviour when considered in terms of maturity, supply chain depth, delivery complexity, and escalation risk.
- As a result, effective long-horizon transmission planning requires explicit consideration of when a technology can be relied upon, not only what it can deliver.
- Architecture plays a central role in managing uncertainty. By combining mature and emerging technologies within coherent system architectures, Transpower can align near-term delivery confidence with longer-term flexibility and avoiding premature and irreversible commitments.

Cost Benchmarking

- Mature HVAC technologies exhibit relatively predictable cost behaviour,
- HVDC technologies provide valuable controllability but introduce higher capital intensity and escalation sensitivity,
- Emerging technologies, while strategically important, remain unsuitable for early commitment due to maturity and delivery risk.

When viewed through a temporal lens, no single technology or architecture provides an optimal solution across all planning horizons. Instead, disciplined sequencing, architecture-led decision-making, and explicit recognition of uncertainty are required to balance system performance, cost exposure, and delivery risk over time.

This document applies a horizon-based framing to summarise how transmission technologies, architectures, and cost behaviours evolve across near-, medium-, and long-term planning contexts. The detailed mechanics of this framework, including decision triggers and transition logic, are provided in the separate Horizon Model Supporting Document.

Together, the Phase 3 Main Report, this Technology Supporting Document, and the Horizon Model Supporting Document provide Transpower with a comprehensive and defensible basis for making informed transmission planning decisions under uncertainty.

1 Introduction

1.1 Purpose and Scope

This Technology Supporting Document provides the detailed technical, architectural, and cost evidence underpinning the transmission technology considerations presented in the Phase 3 Main Report.

The document has been prepared to support technical interrogation, auditability, and long-horizon planning, rather than to prescribe specific projects or investment decisions. It deliberately contains material that is more detailed, quantitative, and comparative than is appropriate for inclusion in the main report.

Consistent with Transpower's Phase 3 brief, this document focuses on three primary technology groupings:

- HVDC transmission technologies
- 400 kV HVAC transmission
- International and future transmission technologies not yet deployed in New Zealand

These technology groupings are examined in terms of:

- functional capability
- system integration characteristics
- maturity and deployment confidence
- indicative cost structure and escalation sensitivity

Indicative cost information is provided at AACE Class 5 (conceptual) level and is intended to support comparative assessment only. All values are bounded, normalised where practicable, and grounded in observed international experience.

The Phase 3 Main Report presents the strategic narrative, decision context, and conclusions.

This supporting document provides the technical depth required to make those conclusions defensible.

1.2 Framing the Technology Landscape

Before individual technologies can be compared, it is necessary to establish a clear and consistent framing for how transmission technologies are being considered within Phase 3.

Transpower's Phase 3 brief identifies three primary technology groupings that are relevant to long-horizon transmission planning.

- HVDC transmission technologies
- 400 kV HVAC transmission technologies
- International and future transmission technologies not yet deployed in New Zealand

These groupings are not competing alternatives in a simple sense. Each addresses different system needs, operates over different planning horizons, and introduces different forms of delivery, cost, and escalation risk.

Transmission technologies therefore need to be assessed not only on their standalone technical capability, but on:

- the role they play within an evolving system architecture,

- the maturity of their supply chains and standards,
- the confidence with which they can be delivered within a given timeframe,
- and the degree of flexibility they preserve or constrain over time.

A key challenge in long-horizon planning is that technologies which appear attractive when viewed in isolation can introduce disproportionate risk if relied upon prematurely, while mature technologies can limit future adaptability if applied indiscriminately.

For this reason, the assessment in this document deliberately avoids ranking technologies as “better” or “worse”.

Instead, technologies are examined in terms of what problem they solve, when they are most appropriately deployed, and how their characteristics interact with cost, escalation, and delivery certainty.

This framing underpins the structure of the sections that follow:

- Sections 3 and 4 examine HVDC and 400 kV HVAC technologies respectively, focusing on functional capability and system role.
- Sections 5 and 6 explore hybrid architectures and future technologies, with emphasis on integration complexity and maturity.
- Subsequent sections then consider how technology maturity, timing, and cost behaviour combine to influence escalation exposure and planning risk.

This approach ensures that technology selection is grounded in system need and timing, rather than driven by capability alone.

2 HVDC Transmission Technologies

High Voltage Direct Current (HVDC) transmission technologies play a distinct and increasingly important role in modern power systems, particularly where long-distance transfer, controllability, and weak-system operation are material considerations.

For New Zealand, HVDC technologies are relevant not as a universal replacement for HVAC infrastructure, but as targeted system tools that can address specific constraints and enable future architectural flexibility.

HVDC technologies are best understood as a family of solutions rather than a single technology, with materially different characteristics, maturity profiles, and system implications.

2.1 HVDC Technology Families

HVDC technologies can be broadly categorised into the following groups.

2.1.1 Line-Commutated Converters (LCC) HVDC

Line-Commutated Converter (LCC) technology relies on a robust alternating current (AC) system voltage to facilitate the commutation of thyristors. Consequently, its performance is intrinsically linked to system strength and fault level. The principal advantages and limitations of LCC in the New Zealand context are outlined below:

Strengths

- High efficiency for bulk power transfers
- LCC HVDC technology is particularly well suited to systems with frequent bidirectional power transfers, such as the New Zealand inter-island HVDC link
- Proven performance at capacities exceeding 1.2–2.0 GW
- Established operational history

Limitations for New Zealand

- Requires robust Short Circuit Ratio (SCR); vulnerable as the system transitions to inverter-based generation
- Generates significant harmonics, necessitating large filter banks (occupying up to 50–70% of site footprint)
- Lacks black-start capability
- Susceptible to voltage depressions, which may result in commutation failures
- Limited flexibility in regions with weak grids (e.g., Upper South Island, prospective offshore wind nodes)

Conclusion: While LCC HVDC remains technically robust, its reliance on system strength and limited reactive power control reduces its suitability for widespread application in future low-inertia environments.

2.1.2 Voltage Source Converters (VSC) HVDC

Voltage Source Converter (VSC) technology, particularly in Modular Multilevel Converter (MMC) configuration, has become the contemporary standard. VSC decouples commutation from the AC waveform, enabling reliable operation in weak or disturbed grid conditions.

Strengths

- Independent active (P) and reactive (Q) power control

- Grid-forming capability, including black-start, islanding, and inertia support
- Compact filter requirements, resulting in a reduced site footprint
- Robust performance even at low SCR
- Preparedness for multi-terminal operation
- Suitability for weak or islanded system operation

Relevance for New Zealand

- Facilitates integration of offshore wind resources
- Enhances stability in inverter-dominated grids
- Enables controlled north–south transfers under conditions of low inertia
- Suitable for deployment within hybrid AC/DC transmission corridors

Conclusion: These attributes make VSC HVDC particularly relevant in systems experiencing increasing penetration of power electronics and variable renewable generation.

2.1.3 Hybrid LCC–VSC Architectures and Multi-Terminal Systems

Hybrid HVDC systems combine the bulk transfer efficiency of LCC with the controllability of VSC, while Multi-terminal HVDC architectures enable power transfer between more than two connection points. These configurations offer potential long-term benefits in terms of flexibility and system integration:

Long-Term Relevance (2040–2060)

- Offshore HVDC transmission backbones
- Multi-node injection in the North Island
- Resilience through redundant DC transmission paths
- Strategic HVDC rebuild for the existing inter-island link

Conclusion: Hybrid and multi-terminal HVDC systems are essential for preserving future flexibility and optionality.

Furthermore, hybrid configurations can introduce:

- Increased control complexity,
- More challenging protection requirements,
- Higher reliance on emerging standards and supplier capability.

As such, hybrid and multi-terminal HVDC systems are best treated as contextual technologies within long-horizon planning, rather than as near-term deployment options.

2.2 Functional Role of HVDC in the Transmission System

From a system perspective, HVDC technologies offer capabilities that are fundamentally different from those provided by HVAC transmission.

These include:

- precise control of power flows independent of network topology,
- decoupling of system frequency and phase angle between regions,
- targeted support of voltage and system strength at connection points,
- controllable transfer across constrained corridors.

These characteristics mean that HVDC is most effectively deployed where control, flexibility, and system support are required, rather than purely to increase thermal transfer capacity.

2.3 Suitability Considerations for New Zealand

When considered in a New Zealand context, HVDC deployment must account for:

- existing system strength conditions,
- seismic and geographic constraints,
- limited corridor availability,
- supply chain concentration and lead times.

VSC HVDC is generally better aligned with these conditions than LCC technology, particularly where future system strength may decline or where controllability is valued over raw transfer capability.

However, HVDC technologies also introduce:

- high capital intensity,
- significant converter station costs,
- sensitivity to delivery sequencing and escalation risk.

These characteristics mean that HVDC should be deployed selectively and in alignment with broader system architecture and timing considerations, rather than as a default solution.

2.4 Summary of HVDC Implications

HVDC technologies provide powerful system capabilities, but their value is highly context dependent.

They are most effective when:

- applied to clearly defined system problems,
- integrated within a coherent AC/DC architecture,
- aligned with realistic delivery timelines and maturity assumptions.

The role of HVDC within long-horizon planning is therefore not to replace HVAC infrastructure, but to complement it where controllability, flexibility, and system support are required.

3 400kV Transmission Technologies

400 kV HVAC transmission represents a fundamentally different class of infrastructure to lower-voltage HVAC systems and to power-electronic solutions such as HVDC. Its primary value lies in the provision of system strength, voltage stiffness, and bulk transfer capability at scale.

For New Zealand, 400 kV infrastructure should not be viewed simply as a higher-capacity extension of the existing 220 kV network. Instead, it represents a strategic system-strength tier that can materially influence system stability, fault performance, and long-term network resilience.

3.1 Functional Role of 400kV Infrastructure

The functional benefits of 400 kV HVAC transmission arise from its electrical characteristics rather than from controllability.

Key functional attributes include:

- significantly increased thermal transfer capability per corridor,
- higher fault level contribution and voltage stiffness,
- improved transient and small-signal stability,
- reduced reliance on active control systems for steady-state operation.

These characteristics make 400 kV infrastructure particularly effective in strengthening the backbone of the transmission system and supporting large-scale power transfers between regions.

3.2 Comparison with Existing HVAC Infrastructure

When compared with 220 kV HVAC infrastructure, 400 kV systems deliver disproportionate increases in capability relative to incremental increases in voltage.

However, these benefits are accompanied by:

- larger physical structures and right-of-way requirements,
- increased substation footprint and complexity,
- higher capital cost per kilometre and per terminal,
- more challenging consenting and community engagement considerations.

As a result, the decision to deploy 400 kV infrastructure is less about marginal optimisation and more about step-change system capability.

3.3 Substation and Equipment Considerations

400 kV substations introduce specific design and delivery considerations that materially influence cost, risk, and programme.

These include:

- transformer size and transport constraints,
- increased seismic design requirements,
- extended equipment lead times,
- selection between AIS and GIS configurations.

GIS solutions can mitigate footprint and seismic risks but introduce higher capital cost and greater reliance on specialist suppliers. AIS solutions offer lower equipment cost but increase land and consenting requirements.

3.4 Planning Implications for New Zealand

In a New Zealand context, deployment of 400 kV HVAC infrastructure must consider:

- corridor availability and environmental sensitivity,
- constructability in remote or seismically active areas,
- integration with existing 220 kV assets,
- compatibility with future HVDC overlays or hybrid architectures.

These factors mean that 400 kV infrastructure is best applied selectively, where its system-strength and bulk-transfer benefits are clearly required and can be justified over long planning horizons.

3.5 Summary of 400kV Implications

While 400 kV transmission has not yet been deployed in New Zealand, 400 kV HVAC transmission provides high certainty, high-capability system reinforcement, but with reduced flexibility relative to power-electronic solutions.

Its strengths lie in:

- delivering robust system performance,
- providing voltage and fault-level support, voltage and fault level support arises from both the strength of the transmission network (including lower impedance associated with higher-voltage networks) and the presence of synchronous machines or other equipment capable of providing short-circuit strength
- anchoring long-term network stability.
- A staged development approach may allow infrastructure to be constructed to 400 kV standards while initially operating at lower voltages, enabling capacity expansion when required

Its limitations relate to:

- physical footprint,
- delivery complexity,
- and reduced adaptability once committed.

Accordingly, 400 kV infrastructure is most effective when deployed as part of a coherent long-term architecture, rather than as an isolated upgrade.

4 Hybrid AC/DC Technology Architecture

As transmission systems evolve, neither HVAC nor HVDC technologies in isolation are sufficient to address the full range of system needs over long planning horizons. This has led internationally to the increasing adoption of hybrid AC/DC architectures, where conventional HVAC infrastructure and power-electronic solutions are deliberately combined.

Hybrid architectures are not a technology in their own right. They are a system design approach that seeks to balance:

- system strength and inherent stability,
- controllability and flexibility,
- delivery certainty and long-term optionality.

4.1 Rationale for Hybrid Architectures

Pure HVAC solutions provide high certainty and strong system performance but offer limited controllability once constructed. Conversely, HVDC solutions provide exceptional control but introduce higher capital intensity, greater delivery complexity, and increased exposure to escalation risk.

Hybrid architectures seek to capture the benefits of both by:

- using HVAC infrastructure to provide backbone strength and voltage support,
- deploying HVDC selectively where controllability or decoupling is required,
- staging investment to align commitment with confidence.

This approach allows system capability to evolve without requiring early, irreversible decisions.

4.2 Common Hybrid Architecture Forms

International experience indicates several recurring hybrid architecture patterns.

These include:

- HVAC backbone with HVDC overlay, where HVDC links provide controllable transfer across constrained or strategically important corridors.
- Staged AC-to-DC conversion, where HVAC infrastructure is established initially and supplemented or converted to HVDC as system needs evolve.
- HVDC injection nodes, where HVDC links connect into strengthened AC hubs to provide targeted control and support.

Each configuration presents different trade-offs between flexibility, complexity, and delivery risk.

4.3 Integration and Operational Considerations

Hybrid AC/DC systems introduce integration challenges that do not arise in purely AC or DC networks.

Key considerations include:

- coordination of AC and DC protection systems,
- definition of control hierarchy and operating modes,
- management of harmonic interaction and filtering requirements,

- operational interfaces between controllable and passive assets.

These factors increase design and commissioning complexity and must be addressed early to avoid downstream cost and schedule impacts.

4.4 Delivery and Escalation Implications

From a delivery perspective, hybrid architectures introduce compound risk. While they reduce long-term lock-in, they require careful sequencing of works and clear decision triggers.

If poorly managed, hybrid approaches can:

- defer costs but increase escalation exposure,
- introduce interface risk between asset classes,
- complicate regulatory and approval pathways.

When managed well, however, hybrid architectures offer one of the most effective means of aligning system capability, cost, and uncertainty over long planning horizons.

4.5 Summary of Hybrid Architecture Implications

Hybrid AC/DC architectures provide a pragmatic pathway for managing uncertainty in long-horizon transmission planning.

Their primary value lies in:

- preserving optionality,
- enabling staged investment,
- aligning commitment with confidence.

Their successful application depends on disciplined architecture definition, clear sequencing logic, and integration with technology maturity and cost considerations addressed in subsequent sections.

5 International and Future Transmission Technologies

In addition to HVDC and 400 kV HVAC technologies that are either deployed or actively being considered within New Zealand, there exists a broader set of international and emerging transmission technologies that are relevant to long-horizon planning.

These technologies are not included as near-term deployment recommendations. Instead, they provide context for future system evolution, inform architecture resilience, and help avoid planning decisions that inadvertently constrain future options.

Addendum 1 of this report provides further detail on selective but relevant Transmission Technologies that where an output of our research and study for this report.

5.1 Purpose of Considering Future and International Technologies

Long-horizon transmission planning necessarily involves uncertainty regarding:

- future generation mix,
- system strength requirements,
- technology cost trajectories,
- and regulatory and market evolution.

Considering international and emerging technologies allows Transpower to:

- understand where global practice is heading,
- anticipate potential inflection points in technology maturity,
- protect future corridors and architectural options,
- avoid premature lock-in to system forms that may become suboptimal.

5.2 Categories of Future and International Technologies

For clarity, future and international technologies can be grouped into the following categories.

5.2.1 Advanced HVDC configurations

These include multi-terminal HVDC systems, meshed DC grids, and HVDC networks with dynamic power routing capability.

Such systems are being deployed in parts of Europe and China but remain characterised by:

- evolving protection standards,
- limited operational experience at scale,
- and high integration complexity.

5.2.2 Grid-forming and advanced power electronic technologies

Grid-forming converters and advanced control systems are increasingly used to support stability in low-inertia systems.

While individual components are becoming more mature, system-wide deployment remains dependent on:

- standards development,
- operational philosophy alignment,
- and coordination across asset classes.

5.2.3 Advanced conductors and structural technologies

Developments in conductor materials, tower design, and foundation systems aim to:

- increase power transfer without new corridors,
- improve constructability in challenging terrain,
- reduce visual and environmental impact.

These technologies tend to mature incrementally and can often be deployed opportunistically within existing projects.

5.2.4 Digital and system/artificial intelligence technologies

Digital twins, advanced sensing, and system-wide analytics are increasingly used to improve operational awareness and asset utilisation.

While these technologies do not replace physical infrastructure, they can influence:

- asset loading assumptions,
- maintenance strategies,
- and system planning confidence.

5.3 Maturity and Deployment Considerations

Most future and international technologies exhibit one or more of the following characteristics:

- limited supplier depth,
- evolving standards and interoperability requirements,
- higher capital cost relative to mature alternatives,
- increased commissioning and operational complexity.

As a result, they are best treated as contextual enablers rather than foundational elements of near- or mid-term system design.

5.4 Relevance to New Zealand Planning

In the New Zealand context, future and international technologies primarily serve to:

- inform long-term architectural resilience,
- support corridor protection and optionality,
- guide monitoring of global technology maturity,
- avoid assumptions that limit future system evolution.

They should not be relied upon to resolve near-term constraints or to underpin critical capacity increases without substantial additional evidence.

5.5 Summary of Future Technology Implications

As indicated here and again within the main body of our report greater insight may be gained from following the international trends when it comes to ***'what's next for transmission technology'***

This is due to International and emerging transmission technology's ability to provide valuable insight into possible future system however they carry significant uncertainty.

Their appropriate role in long-horizon planning is to:

- inform, not dictate,
- enable optionality, not lock-in,
- and complement mature technologies rather than displace them prematurely.

The interaction between technology maturity, timing, and system role is explored further in the following section on technology maturity mapping.

6 Technology Maturity Mapping and Temporal Readiness

Once transmission technologies have been identified and characterised, the next critical question is not whether they are technically feasible, but when they can be relied upon to perform as part of a national transmission system.

Long-horizon transmission planning introduces a fundamental tension. Decisions must often be made years before technologies reach full maturity, while delaying decisions in anticipation of future capability can materially increase cost, delivery risk, and exposure to system constraints.

This tension means that technology assessment cannot be static.

A technology that appears attractive in principle may carry unacceptable delivery or escalation risk if relied upon too early, while a mature technology may provide high certainty but limit long-term adaptability if applied indiscriminately.

For this reason, technologies must be understood not only by what they do, but by how their maturity, reliability, and integration characteristics evolve over time.

6.1 Purpose of Maturity Mapping

Technology maturity mapping provides a structured way to:

- distinguish between technologies that can be confidently deployed in the near term,
- identify technologies that become viable as system conditions and supply chains evolve,
- and recognise technologies that, while promising, should remain contextual rather than determinative in current planning.

By explicitly mapping maturity against time, Transpower can:

- avoid premature reliance on emerging technologies,
- reduce exposure to escalation driven by immature supply chains,
- and align investment decisions with delivery confidence.

6.2 Maturity as a Planning Consideration

Technology maturity influences more than technical performance. It directly affects:

- supplier depth and competition,
- lead times and procurement risk,
- regulatory and standards acceptance,
- commissioning complexity and operational confidence.

As a result, maturity becomes a proxy for delivery certainty, not just innovation readiness.

Technologies with similar functional capability can therefore present very different risk profiles depending on their maturity and deployment history.

6.3 Relevant Maturity of Transmission Technologies

When considered across the long-term planning horizon, transmission technologies exhibit markedly different maturity trajectories.

Broadly:

- conventional HVAC technologies demonstrate high maturity and predictable delivery behaviour,
- contemporary HVDC technologies continue to mature rapidly but retain higher complexity and escalation sensitivity,
- advanced and emerging technologies show promise but lack the deployment history required for reliance in critical system roles.

Understanding these trajectories is essential for sequencing investment and managing escalation exposure.

6.4 Long-Horizon Maturity Mapping

The maturity mapping below illustrates the relative progression of key transmission and enabling technologies across the long-term planning period (2025–2060).

The mapping does not represent a prediction of adoption.

Instead, it provides a visual framework for understanding:

- how confidence in different technologies evolves,
- why their appropriate role in the system changes over time,
- and how timing interacts with risk and cost behaviour.

Figure 6-1. illustrates the relative maturity progression of key transmission and enabling technologies across the long-term planning horizon. This horizon outlook has been developed based on global evidence and best practice and is directly relatable to the Te Kanapu journey for New Zealand.

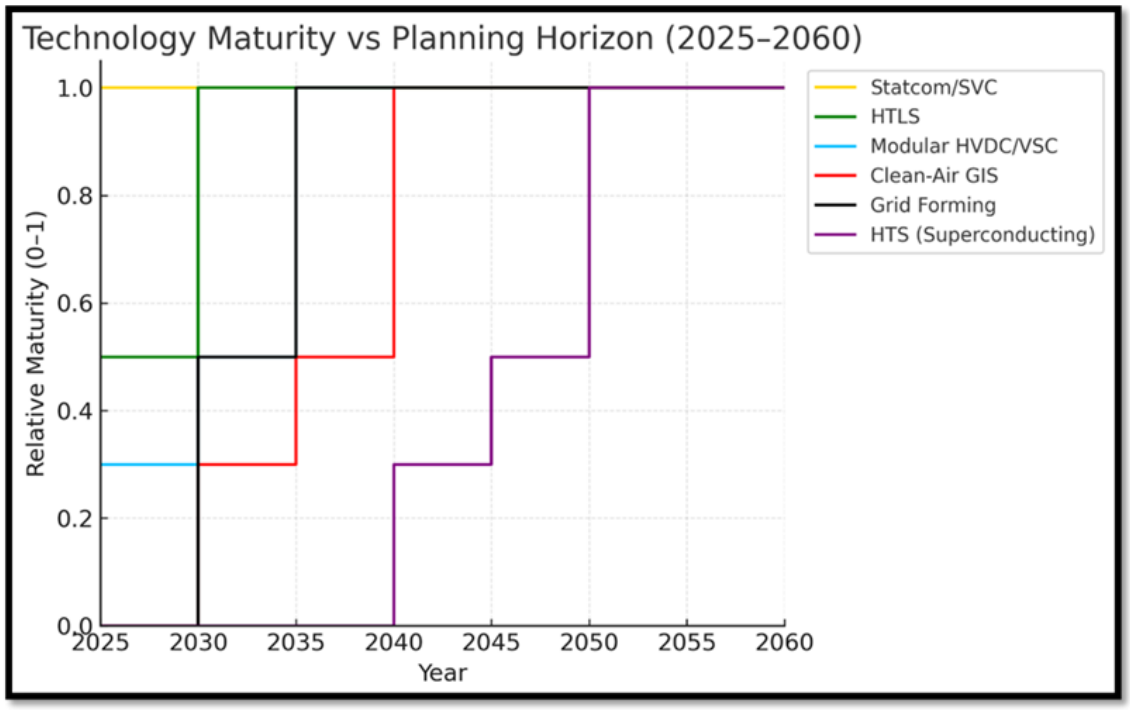

Figure 6-1 Technology Maturity Mapping

6.5 Implications for Subsequent Analysis

The maturity mapping establishes the foundation for:

- evaluating architecture options,
- understanding escalation sensitivity,
- and assessing cost behaviour under different delivery timelines.

In subsequent sections, this temporal understanding of technology maturity is used to:

- frame comparative cost benchmarking,
- explain non-linear escalation behaviour,
- and support structured decision-making under uncertainty.

7 Cost Benchmarking and Comparative Behaviour

This section establishes a comparative, evidence-based view of transmission technology cost behaviour to support long-horizon planning and escalation assessment.

The intent is not to forecast project-specific outturn costs, but to:

- understand relative cost scale between technologies,
- identify dominant cost drivers,
- expose escalation sensitivity by technology and architecture,
- and support the escalation logic applied in Phase 3.

All costs presented are:

- indicative and conceptual (AACE Class 5),
- expressed in real terms,
- normalised where practicable,
- and derived and benchmarked from observed international and local experience.

7.1 Benchmarking Approach

Cost benchmarking has been developed using the following principles:

- triangulation across multiple international and local jurisdictions to avoid single-source bias,
- separation of line / route costs from terminal / substation costs,
- normalisation by voltage class and configuration,
- explicit identification of supply-chain-driven escalation sensitivity.

Benchmarks are intended for comparative planning purposes only and should not be interpreted as budget estimates.

7.1.1 Overhead Transmission Line

Table 7.1-1 Overhead Transmission Line Cost Benchmarks (NZD, real, Class 5)

Technology	Configuration	Indicative Cost Range (NZD$m/km)	Key Cost Drivers
HVAC	220 kV OHL	$2 - $4	Structures, foundations
HVAC	400 kV OHL	$4 - $7	Structure size, access
HVDC	±320 kV OHL	$6 - $9	Insulation, geometry
HVDC	±525 kV OHL	$7 - $10	Specialised materials

Key observation:

HVDC line costs are higher than HVAC primarily due to structural geometry, insulation requirements, and conductor configuration rather than conductor material alone.

7.1.2 Substation and Converter Station Cost Benchmark

The benchmark cost range reflects a typical greenfield 400 kV transmission substation with multiple line bays and transformer positions, inclusive of primary plant, protection and control systems, civil works, and grid integration.

Table 7.1-2 Terminal Asset Cost Ranges

Asset Type	Configuration	Indicative Cost Range (NZD$m)	Dominant Cost Components
HVAC Substation	400 kV AIS	$250 - $350	Land, transformers
HVAC Substation	400 kV GIS	$350 - $450	GIS modules, civils
HVDC Converter	VSC ±320 kV	$700 - $1,000	Valves, controls
HVDC Converter	VSC ±525 kV	$1,000 - $1,400	Supplier concentration

Key insight:

For HVDC projects, converter stations typically represent 50–65% of total project capital cost, making them the dominant escalation risk component.

7.1.3 Dominant cost drivers by technology

Table 7.1-3 Cost Driver Sensitivity by Technology

Technology	Primary Cost Drivers	Typical Lead Time	Escalation Sensitivity
220/400 kV HVAC	Transformers, GIS	18-30 months	Low-Medium
HVAC Lines	Structures, civils	12-24 months	Medium
VSC HVDC Lines	Towers, conductors	24-36 months	Medium-High
VSC HVDC Converters	Valve stacks	42-60 months	High

Escalation sensitivity increases materially where:

- supplier competition is limited,

- manufacturing lead times exceed two years,
- equipment is bespoken rather than standardised.

7.1.4 Escalation sensitivity by architecture

Table 7.1-4 Architecture-Level Escalation Exposure

Architecture	Capital Intensity	Cost Certainty	Escalation Exposure
Pure HVAC	Medium	High	Low-Medium
HVAC + HVDC Overlay	High	Medium	High
Staged Hybrid	Medium-High	Medium	Managed
DC-Led Architecture	Very High	Low-Medium	High

Hybrid staged architectures demonstrate the most balanced cost-risk profile by deferring irreversible commitments until greater certainty is available.

7.1.5 Cost versus delivered capability

Table 7.1-5 Indicative Cost vs Capability Comparison

Technology	Relative Cost	Controllability	Corridor Efficiency
400 kV HVAC	Medium	Low	Low
HVAC + Compensation	Medium	Medium	Medium
VSC HVDC	High	Very High	High

This comparison reframes cost as a function of capability delivered, rather than absolute expenditure.

7.2 Implications for Escalation Modelling

The cost characteristics presented in this section demonstrate that:

- escalation behaviour is technology-dependent,
- escalation is often non-linear for power-electronic assets,
- early commitment to immature technologies amplifies cost risk.

These observations directly inform the escalation curves and modelling approach applied in Phase 3.

8 Integrating Technology, Maturity, Architecture and Cost

The preceding sections demonstrate that transmission technology selection cannot be treated as a series of isolated choices. Technology capability, maturity, architecture, and cost behaviour are tightly coupled, and decisions made in one dimension directly influence outcomes in the others.

For long-horizon planning, the central challenge is not identifying the most capable technology, but aligning capability with maturity, delivery confidence, and acceptable escalation exposure over time.

8.1 Technology Choice as a System Decision

Technologies that appear similar when assessed on capability alone can exhibit materially different behaviour when considered in terms of:

- delivery complexity,
- supply chain depth,
- escalation sensitivity,
- and integration risk.

As a result, technology selection must be approached as a system-level decision, rather than as a component optimisation exercise.

This reinforces the importance of considering:

- the role each technology plays within the broader architecture,
- the timing of its deployment,
- and the degree of optionality it preserves or constrains.

8.2 Interaction Between Maturity and Cost Behaviour

The cost benchmarking presented in Section 8 shows that technology maturity has a direct and measurable influence on cost behaviour.

In general:

- mature technologies exhibit relatively predictable cost trajectories and lower escalation volatility,
- emerging technologies demonstrate higher capital intensity and non-linear escalation behaviour,
- immature technologies introduce significant uncertainty that is difficult to manage through contingency alone.

These characteristics mean that when a technology is deployed is often as important as which technology is selected.

8.3 Architecture as a Risk Management Tool

Architecture provides the mechanism through which technology, maturity, and cost can be aligned.

Hybrid AC/DC architectures, in particular, allow:

- mature technologies to be used where certainty is required,
- emerging technologies to be introduced incrementally,
- irreversible commitments to be deferred until confidence increases.

In this sense, architecture becomes a risk management instrument, not merely a technical design choice.

8.4 Architecture as the Integrating Mechanism

While individual technologies can be assessed in isolation, transmission systems are delivered and operated as integrated architectures.

Architecture provides the mechanism through which technology capability, maturity, and cost behaviour are combined into a coherent system form.

Different architectural configurations expose Transpower to materially different risk, flexibility, and escalation outcomes, even where similar technologies are involved.

The architectural analysis below in figure 2 illustrates how different combinations of HVAC, HVDC, and enabling technologies perform when assessed across multiple dimensions, including maturity, delivery confidence, flexibility, and cost exposure.

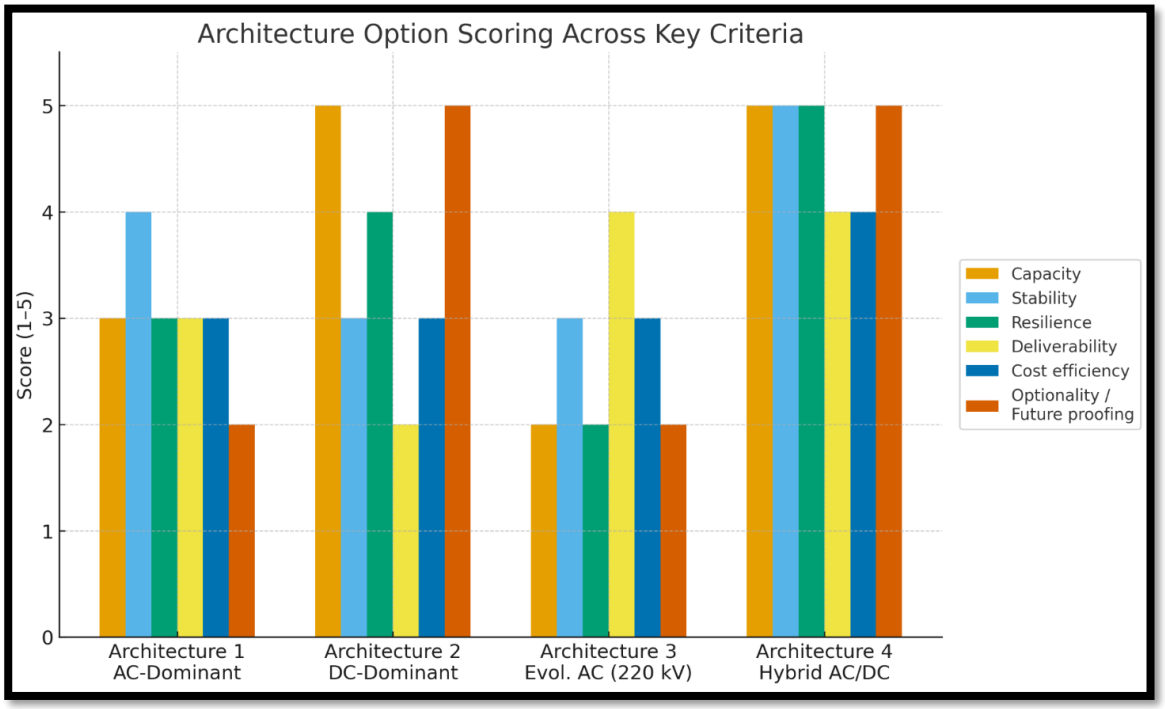

Figure 8.1 Comparative Architecture Scoring

The architectural assessment as shown in figure 2 highlights that:

- Architectures dominated by mature HVAC assets provide high certainty but limited adaptability,
- Architectures reliant on early HVDC commitment introduce higher escalation and delivery risk,
- Hybrid architectures provide a balance between certainty and flexibility by staging commitment,

- Architectural choice materially influences risk exposure independent of individual technology selection.

Addendum 2 of this report contains further analysis detail and the resulting scoring matrix for architectural comparison

8.5 Managing Escalation Through Sequencing

Escalation exposure is most acute where:

- high-capital technologies are committed early,
- delivery timelines extend beyond periods of high uncertainty,
- supply chains are shallow or constrained.

Sequencing investment in line with maturity progression allows escalation exposure to be:

- reduced,
- deferred,
- or actively managed.

This reinforces the importance of linking technology selection and architecture decisions to clear temporal logic.

8.6 Implications for Long-Horizon Planning

When considered together, the analysis in this document indicates that:

- no single technology provides an optimal solution across all horizons,
- early over-commitment increases cost and delivery risk,
- excessive deferral can constrain system performance and increase long-term cost.

Effective long-horizon planning therefore requires:

- disciplined sequencing,
- architecture-led decision-making,
- and explicit recognition of uncertainty.

9 Horizon-Based Framing and Implications for Decision-Making

The analysis presented in this Technology Supporting Document demonstrates that transmission technology selection is inherently a temporal problem, not simply a technical one.

Technologies differ not only in what they can deliver, but in when they can be relied upon, how confidently they can be delivered, and how their cost and risk profiles evolve over time. As a result, long-horizon transmission planning requires a structured way to align technology capability, maturity, architecture, and cost behaviour across different planning periods.

9.1 Introduction of the horizon-based framework

To support this alignment, Phase 3 adopts a horizon-based planning framework that distinguishes between:

- near-term decisions that must be made with high confidence and low tolerance for delivery risk,
- medium-term decisions that can be staged as uncertainty reduces,
- and long-term considerations that inform optionality and strategic positioning rather than immediate commitment.

Within this framework:

- technologies are not assessed as universally “good” or “bad”,
- but as being more or less appropriate within a given horizon, depending on maturity, system role, and escalation exposure.

9.2 Summary of technology positioning by horizon

When viewed through a horizon-based lens, the findings of this document can be summarised as follows:

- **Near-term horizon (Mature)**
  Mature technologies such as conventional HVAC infrastructure, including 400 kV systems, provide high delivery confidence, predictable cost behaviour, and robust system performance. Their role is to anchor system strength and manage immediate constraints.
- **Medium-term horizon (Emerging)**
  Technologies such as VSC HVDC and hybrid AC/DC architectures become increasingly viable as system needs evolve and confidence in delivery increases. These technologies offer enhanced controllability and flexibility but require careful sequencing to manage escalation risk.
- **Long-term horizon (Transformational)**
  Advanced and emerging technologies provide important context for future system forms but should primarily inform optionality, corridor protection, and architectural resilience rather than near-term investment decisions.

This horizon-based positioning explains why no single technology dominates across all periods, and why architecture and sequencing are critical to managing uncertainty.

9.3 Role of architecture within the horizon framework

Architecture provides the mechanism through which horizon-based planning can be operationalised.

By combining mature and emerging technologies within a coherent architecture, Transpower can:

- deliver near-term capability with confidence,
- introduce new technologies incrementally as maturity improves,
- defer irreversible commitments until uncertainty reduces.

In this way, architecture becomes the link between strategy, technology, and delivery reality.

9.4 Relationship to cost and escalation behaviour

The horizon-based framework also provides a direct explanation for the escalation behaviour observed in Section 8.

Early commitment to immature or capital-intensive technologies increases exposure to non-linear escalation, while disciplined staging aligned to horizon readiness allows cost risk to be actively managed rather than absorbed.

This reinforces the importance of integrating horizon logic into both technology selection and investment sequencing.

9.5 Relationship to the Horizon Model supporting document

This Technology Supporting Document applies the horizon-based framework at a summary and illustrative level to explain how different transmission technologies behave over time.

A separate Horizon Model Supporting Document provides the detailed description of the framework itself, including:

- formal definition of each horizon,
- decision triggers and transition logic,
- integration with cost escalation modelling,
- and application within planning and governance processes.

That document should be read alongside this report where a deeper understanding of the framework mechanics is required.

9.6 Closing summary

Taken together, the analysis in this document demonstrates that effective long-horizon transmission planning depends on:

- understanding technology capability,
- recognising maturity and delivery confidence,
- managing cost and escalation exposure,
- and sequencing decisions through a structured temporal framework.

By applying a horizon-based approach, Transpower can move beyond static technology comparisons and instead make robust, adaptable decisions under uncertainty, supported by clear technical and cost evidence.

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Addendum 1. 'Other' Technologies

AD1.1 HTLS Conductors (High-Temperature Low-Sag)

Conductors that use high strength, corrosion resistant composite cores that allow operation at elevated temperatures without excessive sag. This enables existing overhead lines to carry significantly higher currents without major structural upgrades, making them ideal for constrained corridors where building new lines is costly or impractical. Their superior conductivity and durability over most traditional solutions result in reduced transmission losses as well as an extended service life.

- **Benefits**: Increased capacity, avoids new builds and improved efficiency
- **Global Use**: Widely deployed in Europe, US, and Asia-Pacific.

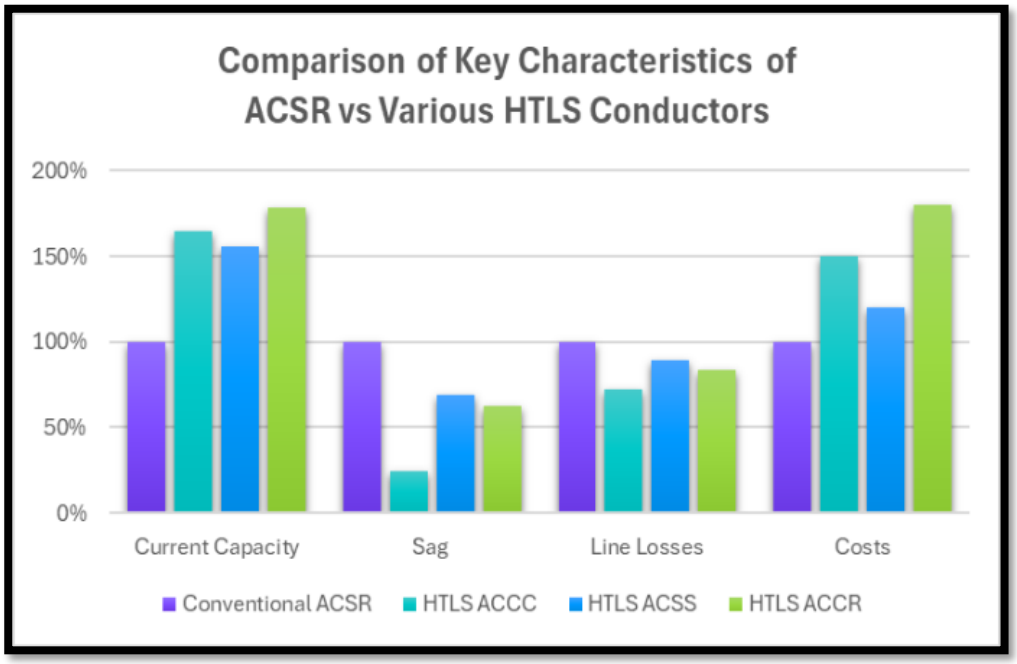


Figure AD.1-1 ACSR vs Various HTLS Comparison

AD1.2 Dynamic Line Rating (DLR)

Dynamic Line Rating (DLR) uses real-time sensors and weather data to continuously adjust the thermal ratings of transmission lines rather than relying on conservative static ratings. DLR devices can be quickly mounted onto existing lines without service interruption by utilising drones or other methods. By accounting for actual environmental conditions, DLR unlocks additional capacity and improves asset utilisation without the need for major upgrades.

- **Benefits**: Additional line capacity, reduced congestion and curtailment
- **Global Use**: Commercial in Europe and US, pilots globally, recognised by IRENA and FERC

AD1.3 Gas-Insulated Lines (GIL)

Gas-insulated transmission lines (GIL) use SF_6 or alternative insulating gases within sealed enclosures, typically installed in underground tunnels or ducts. They provide high-capacity transmission in space-constrained environments and offer resilience against environmental and seismic challenges.

- **Benefits**: High-capacity transmission in space-constrained environments and enhanced reliability
- **Global Use**: Large use seen in Europe, other projects seen in US and Asia

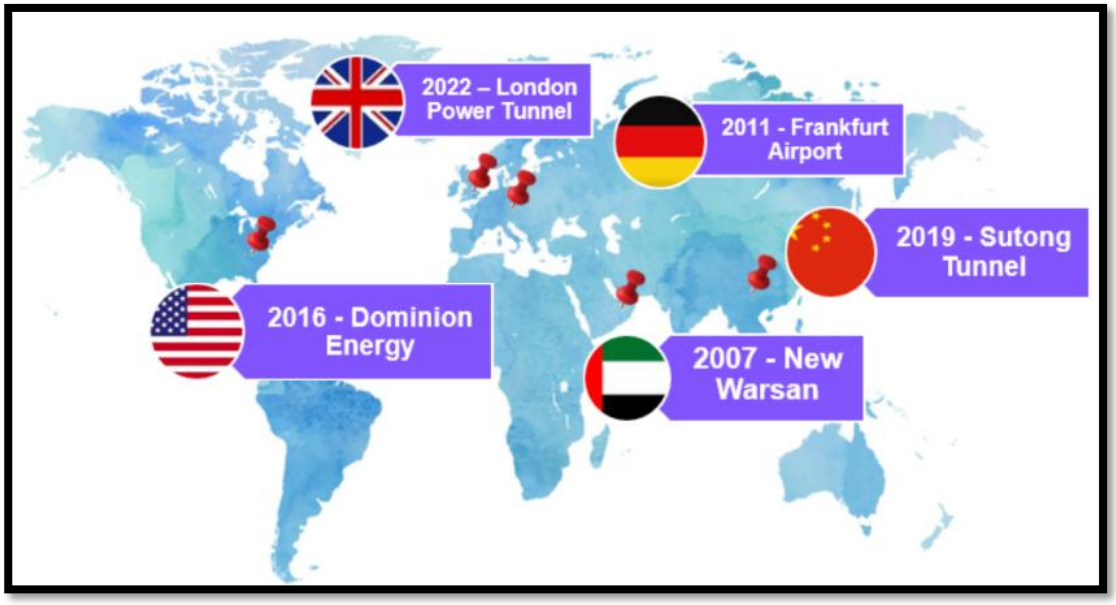


Figure AD.1-2 Key Global GIL Installations

AD1.4 Multi-Terminal HVDC

Multi-terminal HVDC systems enable multiple injection and withdrawal points within the same network, providing enhanced power flow control and operational flexibility. Unlike point-to-point HVDC links, these systems allow the creation of meshed HVDC grids, which simplify the interconnection of different power systems and facilitate large-scale integration of renewable energy sources such as offshore wind and solar farms. Meshed grids also provide redundancy, allowing power rerouting during faults or maintenance.

- **Benefits:** Grid flexibility, redundancy and renewable integration
- **Global Use:** Only low scale projects, large scale in pilot stage, EU projects (e.g. interOPERA), German TSO initiatives underway

AD1.5 Hybrid AC/DC Reinforcement

Hybrid AC/DC reinforcement combines AC and DC circuits in shared corridors to increase capacity and enhance grid flexibility. The inclusion of DC links enables efficient long-distance transfer and simplifies integration of inverter-based resources such as wind, solar, and battery storage while maintaining AC's compatibility with existing grids. This approach supports renewable integration in high-demand areas, reduces congestion, and strengthens system stability.

- **Benefits**: Maximises corridor utilisation, grid flexibility, optimised power flow

- **Global Use**: Only research and pilots in EU/China, studies in US.

AD1.6 Phase-Shifting Transformers (PSTs)

Phase-Shifting Transformers (PSTs) are specialised transformers that control active power flow by adjusting the phase angle between interconnected transmission lines. This capability allows operators to reroute power, optimising network loadability and improving congestion management. By reducing the risk of overloads, PSTs enhance overall grid stability and support renewable integration by managing variable power flows from intermittent sources.

- **Benefits**: Congestion management, grid stability, renewable integration
- **Global Use**: Mature technology used extensively around the world

AD1.7 Advanced Power Flow Controllers (APFCs)

Advanced Power Flow Controllers (APFCs) are power electronics devices designed to dynamically control active power flow in transmission networks. Unlike traditional solutions such as PSTs, APFCs can redirect power flows in real time by adjusting line impedance and voltage phase angle using high-speed electronic controls. They are modular and easy to install on preexisting lines or move between lines if need be. Their fast-acting nature is beneficial for highly congested grids or systems with high renewable penetration to control active power flow dynamically.

- **Benefits**: Congestion management, modularity, low lead times and simplified delivery
- **Global Use**: Commercial use seen in US, Australia, Europe (e.g. Smart Wires), although large-scale utility implementation is still uncommon.

AD1.8 SF_6-Free GIS

SF_6-Free switchgears replace traditional SF_6 insulation with alternative mediums, such as fluoronitrile blends or air insulation. SF_6 gas has an extremely high global warming potential, so phasing the gas out significantly reduces the carbon footprint of the switchgear over its life cycle. This technology aligns with global decarbonisation targets, with the EU mandating that SF_6 insulation is ruled out by 2030.

- **Benefits**: Reduced carbon footprint, regulatory compliance
- **Global Use**: MV widely commercial; HV in pilot stage (e.g. Siemens Blue GIS, Hitachi EconiQ)

AD1.9 Digital Substations

Digital substations involve digitising a portion of a substations secondary system. Uses fibre-optic cable and communication protocols instead of analogue equipment to monitor, control and manage electrical assets. This reduces cabling and physical footprint as well as improves reliability by enabling advanced monitoring and cybersecurity features. Modern digital substations utilise IEC 61850, an international standard that helps standardise all digital substations.

- **Benefits**: Reduced cabling, interoperability, improved reliability and safety,
- **Global Use**: Becoming standard practice for most new builds globally

AD1.10 AI-Based Stability Orchestration and Load Management

AI-driven platforms provide a range of functions, including optimising power flow, predicting faults, and enabling real-time demand management and load shifting. They support congestion management and power rerouting, which is essential for managing the variability of intermittent energy sources.

- **Benefits**: Dynamic congestion management, predictive maintenance and fault detection
- **Global Use**: Limited functionality in some utilities, primarily in the US, pilots advancing rapidly in Europe and the US

AD1.11 Nationwide Demand-Management Platforms

These platforms allow coordinated control of distributed resources and flexible loads at a national scale. This allows large-scale demand response, improving reliability in the grid and improved integration of distributed energy resources (DERs).

- **Benefits**: Enhanced reliability, DER integration
- **Global Use**: Deployed in US/EU, vendors include GE, GridOS, AutoGrid

AD1.12 Compact Towers

Space efficient transmission towers designed for constrained corridors, typically consisting of single poles instead of lattice structures. They reduce visual impact and corridor width, easing consenting challenges and enabling reinforcement where traditional towers are impractical.

- **Benefits**: Reduced footprint, improved aesthetics, environmentally friendly resources
- **Global Use**: Implemented in Denmark, Netherlands, Germany, UK (ECP, T-pylon, compactLine)

Figure AD.1-3 T-pylons used in the UK

AD1.13 Cost Benchmarking

The table below presents indicative AACE Class 5 cost benchmarks for emerging and advanced transmission technologies as described in this addendum.

Values are provided for comparative and long-horizon planning purposes only (Class 5 benchmarks) and should not be interpreted as project-specific estimates.

Table AD.1-1 Further cost benchmarking

Technology	Primary Cost Drivers	Indicative CAPEX (Class 5)	Indicative OPEX	Benchmarks & Examples
HTLS Conductors	Advanced alloy/composite materials, specialised stringing, outage coordination	USD 70k–120k per km (conductor) + USD 20k–40k per km installation	Comparable to conventional conductors	Ofgem RIIO; North American uprating programs; CIGRÉ WG B2
Dynamic Line Rating (DLR)	Sensors, communications, data platforms, analytics integration	USD 30k–80k per monitored line section	Low; data and analytics services	Transgrid TL39 Infravision trial (AUD 1.78m for 114 km); UK National Grid trials
Gas-Insulated Lines (GIL)	Civil tunnelling, specialised installation, gas handling	GBP 10–18 million per km	Low; specialist maintenance	London Power Tunnels; German urban transmission projects
Multi-Terminal HVDC	Converter stations, DC protection, controls	USD 500–900 million per converter station	Moderate; power electronics maintenance	North Sea multi-terminal HVDC concepts; CIGRÉ TBs
Hybrid AC/DC Reinforcement	HVAC + HVDC interfaces, converter integration	Typically 10–30% CAPEX premium over HVAC-only solutions	Comparable to combined systems	Ofgem hybrid corridor studies; EU offshore grid assessments
Phase-Shifting Transformers	Large core steel, copper windings, transport logistics	USD 15–40 million per unit	Low–moderate	European interconnector flow control installations
Advanced Power Flow Controllers (FACTS)	Power electronics, integration complexity	USD 30–120 million per installation	Moderate	STATCOM/SVC deployments in weak grids
SF_6-Free GIS	Alternative insulation, layout constraints	10–50% premium over conventional GIS	Comparable	European utility pilots; OEM disclosures
Digital Substations	Merging units, cyber systems, engineering design	USD 5–15 million per substation uplift	Low–moderate	IEC 61850 deployments (EU, UK)
AI-Based Stability Orchestration	Software platforms, system integration	NZD 50–150 million (platform scale)	NZD 5–15 million per annum	Early-stage utility pilots (conceptual)
Compact Towers	Custom tower design, foundations, urban access	20–60% premium per structure	Comparable	Urban corridor upgrades (EU, Asia)

Note: **Indicative costs are provided at AACE Class 5 level for comparative purposes only and are provided in 2023 real terms drawn from international and local sources. Actual project costs will vary materially based on corridor characteristics, delivery strategy, regulatory requirements, supply chain conditions, and timing.**

AD1.14 Detailed Breakdown

The following table provides a detailed breakdown of each technology mentioned above within this addendum, outlining its key benefits and the associated risks or considerations. This section is intended to give deeper insight into the practical implications of these solutions, whilst also adding additional value to Transpower as complementary data for items 1-3 of the Phase 3 brief. The next three tables highlight both the advantages the challenges/risks that may arise during any consideration or implementation process.

Table AD.1-2 Benefits and Risks Breakdown

Technology	Benefits	Challenges/Risks
HTLS Conductors	• **Increased capacity:** Higher thermal limits enable increased current capacity. • **Avoids new builds:** Ease of retrofitting to existing lines. • **Improved Efficiency:** Reduced transmission losses due to increased conductivity. • **Lower Lifetime Costs:** Extended service life and reduced maintenance due to fatigue resistant composite cores. • **Lower sag:** Minimises chances of electrical faults and enhances safety.	• **Higher upfront costs:** Advanced materials required increases cost • **Installation complexity:** Specialised tools and training required in most cases
Dynamic Line Rating (DLR)	• **Increases transfer capability:** Enables higher utilisation of existing lines. • **Optimised grid operation:** Supports data driven decisions that enable a more flexible and responsive grid. • **Reduced Congestion and Curtailment:** Improves power flow and minimises renewable energy curtailment.	• **Integration Complexity:** Challenges with interfacing with SCADA and EMS • **Data Accuracy:** Inaccurate sensor readings could lead to misjudgements in dynamic line rating assessments.
Gas-Insulated Lines (GIL)	• **Space-Efficient Design:** Cable insulation enables installation in urban or space-constrained environments. • **High-Capacity Transmission:** Supports greater power transfer compared to conventional lines. • **Extended Service Life:** Longer lifespan than traditional overhead transmission lines	• **High Initial Costs:** Specialised materials and skilled labour increase upfront investment. • **Environmental Concerns:** Current solutions use SF_6 gas, which poses environmental risks if leaked, alternatives are still under development. • **Installation Complexity:** Requires skilled manpower.
Multi-Terminal HVDC	• **Grid Flexibility:** Supports meshed DC networks, especially useful for renewable hubs. • **Improved Reliability:** Meshed networks allow redundant paths, increasing reliability in case of contingencies or outages.	• **Fault Management:** Fast DC breakers and protection schemes are still evolving and can be quite costly • **High Upfront Costs:** Higher amount of converter stations, DC

	• **Renewable Integration:** Assists the connection of various large scale renewable projects.	breakers and control systems increase initial investment. • **Technology Maturity:** Large scale multi-terminal HVDC and DC meshed grids are still under development. • **Integration Complexity:** Requires higher SCADA and EMS coordination
Hybrid AC/DC Reinforcement	• **Grid Flexibility:** Assists integration of DC resources such as DER's, storage and EV chargers. • **Optimised Power Flow Management:** Reduces unnecessary AC/DC conversions between generation and load, improving efficiency. • **Enhanced Resilience:** Hybrid systems can provide redundancy and leverage DC connected resources like energy storage to help stabilise the grid during contingencies • **Maximises Existing Corridor Utilisation:** Increases power transmission in already existing corridors	• **Fault Management:** Faults on AC and DC sides require different protection strategies and technologies. • **High Upfront Costs:** Higher amount of converter stations, protection devices and control systems increase initial investment. • **Technology Maturity:** Lack of mature standards or regulations. • **Coordination Difficulties:** Requires sophisticated integration of SCADA and EMS systems as well as advanced coordination of assets
Phase-Shifting Transformers	• **Power Flow Control:** Redirects power flow to underutilised lines to maximise loadability and use of existing infrastructure. • **Proven Technology:** Reliable devices that have been used globally for decades • **Renewable integration:** Helps manage variability and congestion, typical of high renewable grids.	• **Limited Dynamic Response:** Can only provide slow, mechanical adjustments • **High Upfront Costs:** Large, heavy and expensive devices that require lots of space. • **Long Lead Times:** Manufacturing complexity and specialised logistics for transportation result in long lead times
Advanced Power Flow Controllers (APFCs)	• **Dynamic Power Flow Control:** Redirects power flows in real time, critical for grids with high number of renewables. • **Modular:** Easy to install on existing lines without major civil work, resulting in cheaper and faster deployments. • **Low Lead and Delivery Times:** Significantl y lower deployment times and transportation requirements compared to PSTs	• **Technology Maturity:** Limited commercially available options or large-scale utility adoption
SF_6-Free GIS	• **Regulatory compliance:** Many regulatory measures are being implemented globally, such as in the EU, to limit the use of SF_6 • **Reduced carbon footprint:** SF_6 has a global warming potential (GWP) that is 24,300 time higher than CO2 • **Transition Pathway:** Most solutions provide designs that can replace	• **Stability Under Various Operating Conditions:** May not perform well under extreme conditions, such as extreme temperatures. • I**ntegration with Existing Assets**: Extensive research and testing to ensure alternative gases do not compromise integrity of existing switchgear components.

	conventional GIS with minimal disruptions.	• **HV Applications**: High Voltage SF_6-Free GIS is still in development.
Digital Substations	• **Reduced Cabling:** Fiber optic cables replace copper wires, reducing installation costs. • **Enhanced monitoring:** Advanced monitoring allows predictive maintenance and fast response time results in faster fault isolation and protection, • **Interoperability:** Devices from different vendors can communicate easily, reducing integration difficulties	• **Cybersecurity:** Reliance on networked system increases attack surface for hackers, requiring proper security measures to be implemented • **Installation Complexity:** Requires high technical expertise for configuration, testing, and commissioning of IEC 61850 systems
AI-Based Stability Orchestration and Load Management	• **Dynamic Congestion Management:** AI can actively redistribute power flows and optimise renewable dispatch, reducing curtailment and improving asset utilisation. • **Predictive Maintenance:** Predicts equipment failure, reducing downtime. • **Grid Stability:** Predicts faults and controls power flows to reduce the risk of outages and increase stability	• **Misjudgement and Bias:** May make incorrect decisions, typically when abnormal conditions occur. • **Cybersecurity:** Reliance on networked system increases attack surface, requiring proper security measures to be implemented • **Integration Complexity and Cost:** High upfront cost for sensors and AI platforms, as well as complexity integrating into existing SCADA. • **New Technology:** The technology is still new, with some pilots existing globally but limited large scale commercial deployments.
Nationwide Demand-Management Platforms	• **Enhances Reliability:** Reduces stress on the grid during peak demand periods, helping prevent outages • **Renewable Integration:** Balances variability in renewable generation and helps integrate distributed energy resources (DERs)	• **Operational Complexity:** Managing many assets in real time requires strong algorithms and failsafe mechanisms as well as advanced coordination with SCADA and EMS. • **Consumer Participation:** Success depends on customer willingness to enrol. • **Limited Large-Scale Experience:** The technology is still relatively new, with some pilots existing globally but limited large scale commercial deployments.
Compact Towers	• **Reduced Footprint:** Minimising land use as well as optimising use of already existing corridors. • I**mproved Aesthetics**: Less visually intrusive than traditional lattice towers • **Modular and Prefabricated:** Allows faster installation	• **Higher Cost:** In most cases increased upfront cost due to specialised design • **Upgrade Difficulties:** Difficult to upgrade existing compact towers if they require more load bearing capacity.

AD1.15 Risk and Reward Maps

The risk and reward maps provide a quick visual comparison of transmission technologies across key performance and implementation factors. Each row represents a technology, and columns show benefit criteria (e.g., capacity increase, efficiency, environmental impact) and risk criteria (e.g., cost, complexity, maturity). Scores range from 1 (low) to 5 (high). This allows the ability to easily identify technologies with the best balance of advantages versus challenges.

Table AD.1-3 Benefits heatmap (Reward)

Benefits						
Technologies	Capacity Increase	Efficiency Improvement	Environmental Benefit	Deployment Speed	Grid Flexibility	Reliability Enhancement
HTLS Conductors	5	4	2	4	2	3
Dynamic Line Rating	3	2	3	5	4	3
Gas-Insulated Lines	4	4	2	2	2	4
Multi-Terminal HVDC	3	4	3	2	5	4
Hybrid AC/DC Reinforcement	4	4	3	2	4	4
Phase-Shifting Transformers	3	2	2	1	4	3
Active Power Flow Controllers	4	3	3	4	5	3
SF_6-Free GIS	1	1	5	3	2	3
Digital Substations	1	3	3	2	4	4
AI-Based Stability Management	3	4	3	2	5	4
Nationwide Demand Management	3	4	3	3	4	4
Compact Towers	3	2	4	4	2	3

Table AD.1-4 Risks heatmap (Challenges)

Risks							
Technologies	Upfront Cost	Installation Complexity	Technology Maturity	Integration Challenges	Environmental Concerns	Operational Complexity	Cybersecurity Risk
HTLS Conductors	3	2	2	2	2	2	1
Dynamic Line Rating	2	2	3	2	1	3	3
Gas-Insulated Lines	5	5	3	3	4	2	1
Multi-Terminal HVDC	5	4	4	5	2	5	3

Hybrid AC/DC Reinforcement	4	4	4	4	2	4	2
Phase-Shifting Transformers	4	4	1	2	1	2	1
Active Power Flow Controllers	3	3	4	3	1	3	2
SF_6-Free GIS	3	3	3	2	1	2	1
Digital Substations	3	4	2	4	1	4	5
AI-Based Stability Management	3	3	5	4	2	4	5
Nationwide Demand Management	4	3	3	4	2	4	4
Compact Towers	3	3	2	2	2	2	1

Addendum 2. Expanded Architecture Detail and Scoring Matrix

AD2.1 Architectural Comparison

As established throughout our report, the future configuration of New Zealand's electricity system cannot be determined solely by technological selections. Rather, the core issue is architectural in nature:

"Which long-term backbone architecture delivers the optimal combination of capacity, stability, resilience, deliverability, cost-effectiveness, future optionality, and alignment with New Zealand's structural constraints?"

This addendum presents a comparative analysis of four plausible transmission architectures:

- AC-Dominant Architecture
- DC-Dominant Architecture
- Evolutionary AC Reinforcement (220 kV-focused)
- Hybrid AC/DC Architecture (Recommended)

Each architecture is assessed against six strategic criteria:

- Transfer capability
- System strength and stability
- Deliverability and consenting feasibility
- Cost per MW delivered and long-term efficiency
- Resilience and redundancy
- Future optionality (offshore, multi-terminal, new load zones)

The evaluation draws upon benchmark costs, technology maturity timelines, global best practices, and New Zealand-specific constraints as outlined in earlier sections of this document.

AD2.2 Architecture 1 — AC-Dominant Backbone

Description
This system is primarily based on upgrades to the 220 kV network, the selective introduction of 400 kV sections, and traditional HVAC reinforcement methods.

Strengths

- Well-established technology with low technical risk
- Wide availability of contractors
- Provides robust voltage support and system strength

Limitations

- The 220 kV network quickly approaches thermal and stability limits
- Implementation of 400 kV requires the development of major new corridors, which face significant consenting challenges
- Prolonged construction timelines
- While system strength is high, controllability is lower

Applicability in New Zealand
This approach is beneficial in localised contexts but is insufficient as a standalone strategy for long-distance transfer, offshore wind integration, and maintaining stability with high penetration of inverter-based resources.

AD2.3 Architecture 2 — DC-Dominant Backbone

Description
This architecture entails the deployment of multiple HVDC corridors, with AC networks primarily serving local distribution purposes.

Strengths
- Outstanding long-distance transfer capability
- High degree of controllability
- Particularly effective for offshore wind integration

Limitations
- Very high capital expenditure for converter stations
- Extended lead times (up to 40 months for critical equipment)
- Limited availability of domestic contractors
- Lower inherent system strength compared to AC networks
- Multi-terminal HVDC technology is still emerging (H2 maturity)

Applicability in New Zealand
While the DC-dominant approach excels in transfer controllability, it faces challenges regarding system strength, deliverability, and short-term stability issues in regions such as NOR, WEK, and Canterbury. It also increases reliance on synchronous support and/or grid-forming inverters.

AD2.4 Architecture 3 — Evolutionary AC Reinforcement (220 kV Focused)

Description
This approach focuses on incremental scaling of the existing 220 kV network through duplication, targeted upgrades, and selective substation expansions.

Strengths
- Lowest technological risk
- Leverages existing infrastructure and operator expertise
- Lower unit cost (per km) for incremental upgrades

Limitations
- Rapid consumption of available corridor space
- Insufficient to meet long-term capacity requirements
- Necessitates frequent upgrades, leading to escalating lifecycle costs
- Does not adequately facilitate offshore wind or increased South Island to North Island transfer

Applicability in New Zealand
This strategy is suitable only as a tactical or short-term measure.

AD2.5 Architecture 4 — Hybrid AC/DC Backbone (Recommended)

Description
This architecture adopts a layered approach, combining:

- 400 kV AC nodes to deliver system strength, inertia anchoring, and high-capacity AC corridors
- VSC HVDC spines for controllability, offshore wind integration, and dynamic transfer routing
- Enhanced 220 kV integration for local flexibility
- Provision for future multi-terminal HVDC (H2/H3)

Hybrid architectures are now considered global best practice for systems facing high variable renewable energy (VRE) penetration, high capacity, and long-distance transmission requirements.

Strengths
- Balances the system strength of AC with the controllability of DC
- Minimises over-reliance on any single technology
- Facilitates offshore wind integration via DC spines
- Reduces corridor requirements by utilising high-capacity 400 kV lines
- Enables clear sequencing (AC first for strength, DC subsequently for control)
- Compatible with H2/H3 technologies without necessitating premature investment

Limitations
- Demands new competencies in coordinated AC/DC operation
- Requires careful staging to prevent overbuilding
- Complexity in protection and control, though manageable

Applicability in New Zealand
This architecture is fully aligned with the constraints identified in Sections 4 and 5:

- 400 kV addresses system strength requirements in both the North and South Islands
- HVDC enables controlled north–south balancing and offshore readiness
- The hybrid approach reduces consenting risk compared to AC-only solutions
- HVDC mitigates long-term climate and storm-related vulnerabilities associated with overhead lines
- Supports the growth of multi-node industrial centres in both islands

AD2.6 Technical Analysis Results

Following our research and global testing we were able to apply the data to produce a robust rationale and subsequent scoring matrix as the outcome of our architectural analysis. This in turn is what is reflected within figure 2: Comparative Architecture Scoring of this report.

AD2.6.1 Expanded Scoring Matrix

Table AD.2-1 Expanded Scoring Matrix

Criterion	Architecture 1 AC-Dominant	Architecture 2 DC-Dominant	Architecture 3 Evol. 220 kV	Architecture 4 Hybrid AC/DC
Capacity	3	5	2	5
Stability	4	3	3	5
Resilience	3	4	2	5

Deliverability	3	2	4	4
Cost efficiency	3	3	3	4
Optionality / Future proofing	2	5	2	5

AD2.6.2 Expanded Justifications

Table AD.2-2 Expanded Justifications

Architecture	Performance/Characteristics
Architecture 1	Moderate uplift through selective 400 kV nodes, constrained by 220 kV thermal limits
Architecture 2	Largest controllable MW envelope
Architecture 3	Rapidly saturates its capability
Architecture 4	Strongest long-term performance through AC/DC complementarity

AD2.6.3 Stability

Table AD.2-3 Stability

Architecture	Stability	Strength	Controllability	Loading Impact
Architecture 1	Strong inherent stability	AC strength		
Architecture 2		Limited inherent strength	Controllability	
Architecture 3	Adequate			Deteriorates as loading intensifies
Architecture 4	Highest stability	400 kV strength	VSC controllability	

AD2.6.4 Resilience

Table AD.2-4 Resilience

Architecture	Features	Limitations
Architecture 1	Traditional redundancy	Limited routing flexibility
Architecture 2	Dynamic rerouting	Depends on AC strength
Architecture 3	Lowest long-term resilience	
Architecture 4	Highest resilience, AC/DC redundancy, black-start capability	

AD2.6.5 Deliverability

Table AD.2-5 Deliverability

Architecture	Key Point
Architecture 1	Uses familiar AC technologies but faces 400 kV consenting challenges
Architecture 2	Limited by OEM constraints and long lead times
Architecture 3	Easiest to stage and deliver incrementally
Architecture 4	Achievable when modularly sequenced and avoids full AC duplication

AD2.6.6 Cost Efficiency

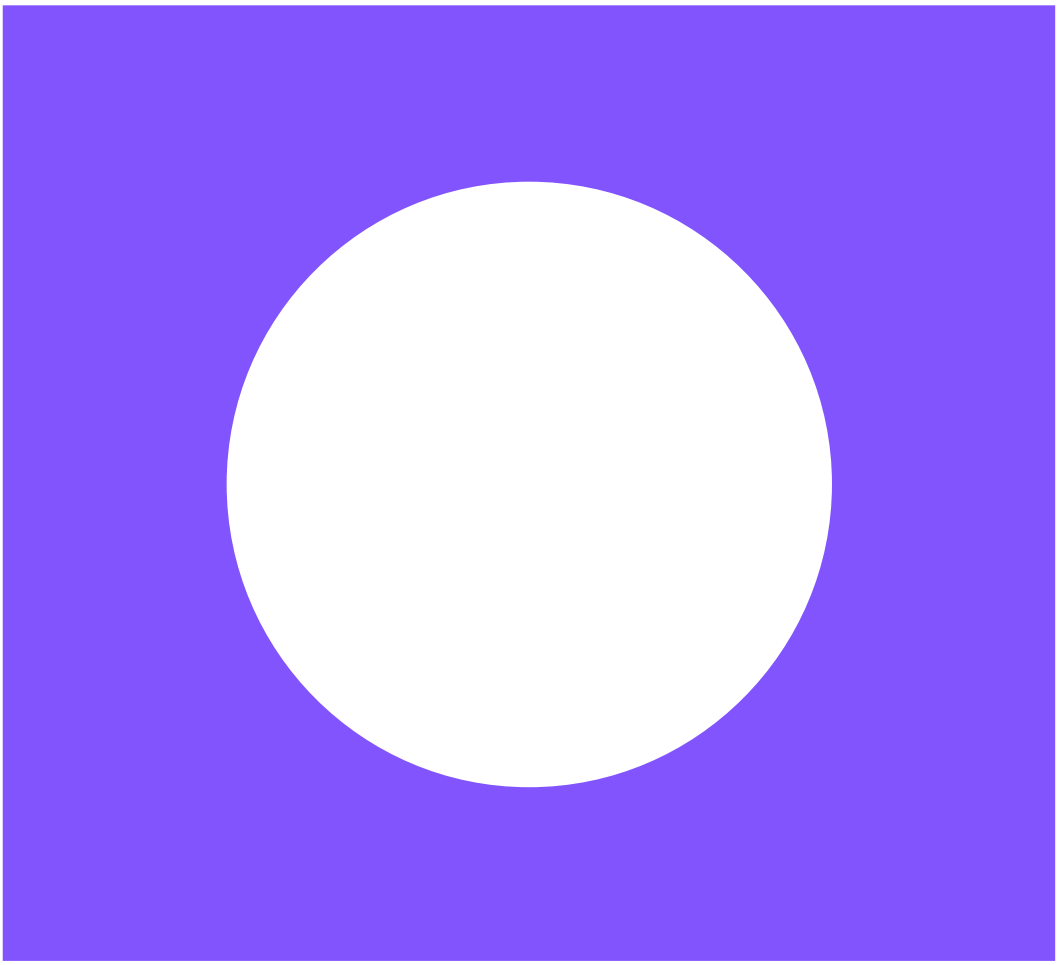
Table AD.2-6 Cost Efficiency

Architecture	Key Feature	Cost Aspect	Efficiency/Upgrade
Architecture 1	Moderate	400 kV substations raise lifecycle costs	
Architecture 2	High converter costs	Offset by MW-km efficiency	
Architecture 3	Low unit cost		Repeatedly requires upgrades
Architecture 4	Balances CAPEX		Long-term efficiency and deferred duplication

AD2.6.7 Optionality & Future Proofing

Table AD.2-7 Optionality & Future Proofing

Architecture	Key Features
Architecture 1	Limited future adaptability
Architecture 2	Supports offshore wind, multi-terminal growth, future injections
Architecture 3	Constrained, lacks long-term scalability
Architecture 4	Strongest alignment with 2050+ requirements, & expansion



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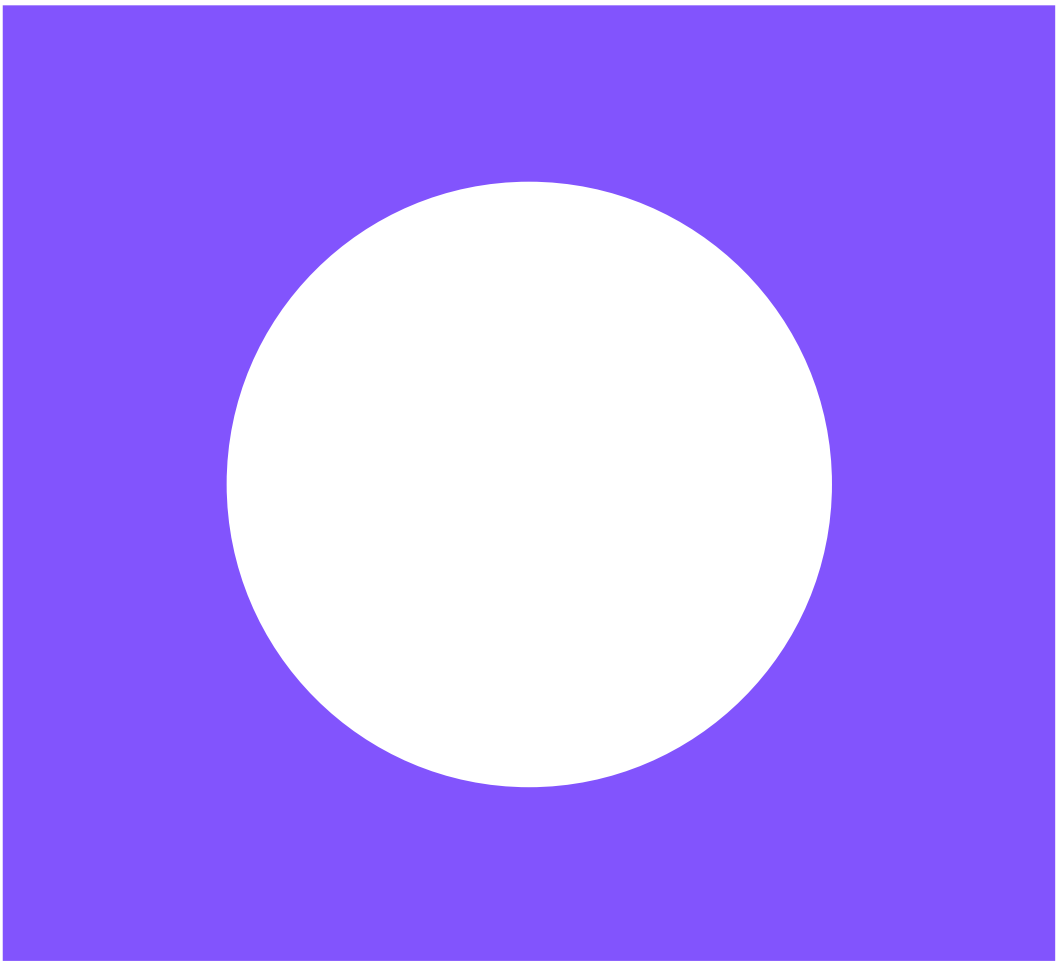

Transpower - Further Development of Class 5 Cost Estimation Models (Phase 3)

Three Horizon Adoption and Escalation Framework

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Contents

Executive summary 1

1 Introduction 2
1.1 Purpose and Relationship to the Main Report 2
1.2 Why Long-Horizon Escalation Requires Structural Treatment 2
1.3 Escalation as a State-Based Phenomenon 2

2 The Three-Horizon Model as an Escalation Lens 4
2.1 Horizon 1 – Mature Deployable Technologies (2025–2030) 5
2.1.1 High-Temperature Low-Sag (HTLS) Conductors 5
2.1.2 FACTS Devices (SVC, STATCOM, TCSC, PST) 5
2.1.3 Digital Substations (IEC 61850-9-2) 6
2.1.4 Composite Poles and Compact Towers 6
2.1.5 Gas-Insulated Lines (GIL) 6
2.1.6 Horizon 1 Summary 7
2.2 Horizon 2 – Emerging Technologies (2030–2040) 7
2.2.1 Hybrid AC/DC Transmission Lines 7
2.2.2 Clean-Air 400 kV GIS (SF_6-Free) 8
2.2.3 Grid-Forming Inverter (GFM) Clusters 8
2.2.4 Distributed FACTS and Edge Power Control 8
2.2.5 Modular HVDC Converter Stations 8
2.2.6 Horizon 2 Summary 9
2.3 Horizon 3 – Transformational Technologies (2040–2060) 9
2.3.1 Multi-Terminal HVDC and HVDC Meshed Grids 9
2.3.2 High-Temperature Superconducting (HTS) Corridors 10
2.3.3 Autonomous Transmission Inspection & Maintenance Systems 10
2.3.4 Synthetic Stability Layer (AI-Orchestrated Inertia & System Strength) 10
2.3.5 Flexible Submarine HVDC “Energy Highways” 11
2.3.6 Horizon 3 Summary 11
2.4 Horizon Transitions Inflection Points and Escalation Inflection Points 11
2.4.1 Escalation Inflection Points and Evidence-Based Transitions 12
2.4.2 Avoiding Premature De-Escalation 12
2.4.3 Staged Commitment and Escalation Moderation 12
2.4.4 Relationship to First-of-a-Kind and Repeat Deployment Effects 12
2.4.5 Learning Effects and the Role of Experience Curves 13
2.4.6 Summary 13

3 Quantitative Construction of Escalation Inputs 14

3.1 Purpose and Role of This Section 14
3.2 What must be numerically defined (baseline metrics required by the model) 14
3.3 Parameter 1: Base escalation anchor (E_base) 14
3.3.1 Evidence streams used 14
3.3.2 Conversion into a numerical value (simple equation) 14
3.4 Parameter 2: Horizon behaviour factor (H_factor) – H1 mature / H2 emerging / H3 transformational 15
3.4.1 Evidence streams used 15
3.4.2 Conversion into a numerical value (simple equation) 15
3.5 Parameter 3: Architecture & maturity factor (A_factor) 15
3.5.1 Evidence streams used 15
3.5.2 Conversion into a numerical value (simple mapping) 16
3.6 Parameter 4: Scale & repetition factor (S_factor) 16
3.6.1 Evidence streams used 16
3.6.2 Conversion into a numerical value (simple equation) 16
3.7 Consolidated escalation model parameter register 16

4 Escalation Equation – Playbook and Worked Examples 18
4.1 Recap – the fixed numerical inputs (from Section 3) 18
4.2 Equation form (and why multiplicative) 18
4.3 Full equation with numerical values – horizon archetypes 18
4.4 When A_factor and S_factor change (technology-specific curves) 19
4.5 How do these parameters connect to the ‘golden’ annual multiplier tables 19

5 TEES Integration – Three-Horizon Implementation, Outputs, and Governance 20
5.1 TEES configuration concept 20
5.2 Pre-calculated annual multiplier tables (2025–2060) 20
5.2.1 H1 – Golden Multiplier (Mature/Known) 21
5.2.2 H2 – Golden Multiplier (Emerging) 22
5.2.3 H3 – Golden Multiplier (Transformational) 22
5.3 How to use H1/H2/H3 together on a single project 23
5.3.1 Why Multi-Horizon Application Is Required 23
5.3.2 Principle of Horizon Segmentation 23
5.4 Worked Example – Mixed-Horizon Transmission Project 24
5.5 Blended Technology Escalation Calculation 24
5.6 Interpretation 25
5.7 Horizon Migration 25
5.7.1 Practical Guidance for Transpower 25
5.8 Reference Python implementation 25
5.9 Validation and governance inside TEES 26
5.10 Failure Modes and Misapplication Risks 27
5.11 Extensibility Beyond Transmission Technology 27

Addendum 1. Project Mapping (The Theoretical Outcome) 28

AD1.1 The Eight Core System Problems 28
AD1.2 Technology → Problem → Project Mapping 28
AD1.3 Technology Adoption Pathways 28
AD1.3.1 Layer 1 — Stabilise & Optimise (2025–2030) 28
AD1.3.2 Layer 2 — Expand & Hybridise (2030–2040) 29
AD1.3.3 Layer 3 — Transform & Enable Exports (2040–2060) 29

Tables

Table 2-1 Three Horizon – Technology Adoption 5
Table 3-1 Three Horizon H_Factor 15
Table 3-2 Three Horizon A_Factor 16
Table 3-3 Consolidated Parameter Register 16
Table 5-1 Golden Multiplier Table Assumptions 20
Table 5-2 H1 – Golden Multiplier 21
Table 5-3 H2 – Golden Multiplier 22
Table 5-4 H3 – Golden Multiplier 22
Table 5-5 Worked Example Input Assumptions 24

Figures

Figure 2-1 Horizon 1 - Mature Technologies Behavioural Map (H1) 7
Figure 2-2 Horizon 2 - Emerging Technologies Behavioural Map (H2) 9
Figure 2-3 Horizon 3 - Transformational Technologies Behavioural Map (H3) 11

Tables

Table AD.1-1 Construct vs Technology Fit 29
Table AD.1-2 Constraint Mapping – Linking constructs to real problems 30

Executive summary

This document provides the technical and mathematical foundation for the Three Horizon Adoption Model referenced in the Phase 3 Main Report. The main purpose is to translate strategic intent into a repeatable, auditable and defensible escalation methodology suitable for direct use within Transpower's TEES environment.

The framework responds to a persistent weakness observed in infrastructure cost planning: the tendency to apply a single averaged escalation rate to fundamentally different technologies, maturity states, and delivery contexts. This practice obscures risk suppresses learning effects and systematically misrepresents the true cost behaviour of complex transmission programmes.

Rather than treating escalation as a time-based or inflation-driven adjustment, the Three Horizon Model reframes escalation as a behavioural outcome. Technologies are classified into three horizons:

- Horizon 1 - Mature
- Horizon 2 - Emerging
- Horizon 3 - Transformational

Each horizon exhibits distinct escalation dynamics, supported by evidence from the Phase 3 Technology Assessment, international benchmarking, architectural analysis, and Phase 2 escalation foundations, which is then parameterised to produce horizon-specific 'Golden Multiplier' for TEES.

A key principle of the framework is that it explicitly prohibits the collapse of horizon behaviour into a single blended escalation rate. Projects containing technologies from multiple horizons, must apply escalation at the component or cost-block level before aggregation. Averaging horizon behaviour at the outset reintroduces the modelling risk this framework is designed to eliminate.

The framework is deliberately scoped to escalation and de-escalation behaviour. It does not attempt to forecast market volatility, macroeconomic shocks, or procurement strategy outcomes. Those effects may be layered separately within TEES. By isolating structural escalation behaviour, the model provides clarity, governance and traceability over one of the most material drivers of long-term cost risk in transmission investment.

The document follows the structured of the Phase 3 Main Report. Section 2 closes out the conceptual foundations and define the boundaries of applicability. Sections 3-5 act as the analytical lynchpin, drawing together qualitative evidence and quantitative derivation into a fully specified escalation formulation. Additionally, sections 4 and 5 demonstrate the model and how it is implemented within TEES, including worked examples for projects containing mixed-horizon technologies. Additionally, sections 4 and 5 demonstrates the model and how it is implemented within TEES, including worked examples for projects containing mixed-horizon technologies.

Overall, this document provides Transpower with a robust, reusable escalation framework that is consistent with prior phases, defensible under regulatory scrutiny, and adaptable to future technology pathways. It is intended not merely as a model, but as a governance tool—one that embeds discipline, transparency, and behavioural realism into long-term transmission cost planning.

1 Introduction

1.1 Purpose and Relationship to the Main Report

This report provides the analytical foundation for the Three-Horizon Adoption Model referenced in the Phase 3 Main Report.

The Phase 3 Main Report introduces the horizon concept at a summary level to explain how escalation and de-escalation behaviour varies across long planning horizons. This document exists to provide the technical logic, structure, and supporting evidence that sit beneath those conclusions.

This report should be read as subordinate to the Main Report, particularly Sections 3 through 8, and in parallel with the Technology Supporting Report, which documents technology maturity pathways, architectural considerations, and benchmark cost evidence.

This document does not prescribe investment decisions, network development pathways, or strategic priorities. Its role is deliberately constrained to supporting the escalation modelling framework by explaining why uniform escalation assumptions are inappropriate over long horizons, demonstrating how escalation behaviour varies with technology maturity and deployment conditions, and translating those concepts into a form suitable for Class 5 cost estimation and implementation within Transpower's cost modelling tools.

Where the Main Report summarises outcomes, this document explains mechanisms behind them. Where the Main Report asserts conclusions, this document demonstrates their analytical foundation that support them.

1.2 Why Long-Horizon Escalation Requires Structural Treatment

Sections 3 and 4 of the Phase 3 Main Report identify escalation as one of the most influential variables in long-term transmission cost estimation. While short time forecasting can rely on inflation-based indices or blended escalation rates, these methods become more unreliable beyond 15 to 20 years as the non-inflammatory drivers begin to dominate cost behaviour.

These structural drivers include technology learning and standardisation effects, supply chain depth and competition, labour market constraints and capability development, exposure to foreign exchange and commodity volatility, and first-of-a-kind versus repeat deployment dynamics. As planning horizons extend toward 2060, these factors increasingly outweigh general inflation meaning that a single escalation assumption across this period risks materially overstating or understating future costs depending on technology and timing.

The Phase 3 approach therefore recognises that escalation is not a uniform process and requires a structured method to reflect how cost behaviour changes over time.

1.3 Escalation as a State-Based Phenomenon

A central premise of the Phase 3 work is that escalation is driven by more than simply the passage of time.

We find that upon deeper analysis, cost behaviour is influenced by the state of a technology and its surrounding delivery environment, including the maturity of the underlying technology, the degree of design standardisation, the availability and competitiveness of suppliers, and the scale and repeatability of deployment.

Technologies in different maturity states exhibit fundamentally different escalation characteristics, even if deployed in the same calendar period. Mature technologies tend to display stable, benchmarkable cost behaviour, while immature technologies are subject to wider cost dispersion and greater uncertainty.

This state-based perspective underpins the need for a framework that can distinguish between fundamentally different escalation environments and apply escalation assumptions accordingly. The Three-Horizon Adoption Model is introduced to provide this structure, where time then becomes a constant progression that affects the state of technology allowing the cost behaviour to behave closer to real-terms

2 The Three-Horizon Model as an Escalation Lens

As established in the preceding sections, escalation behaviour over long planning horizons is driven by the state of technologies and their delivery environments, rather than by time alone. To structure this behaviour in a transparent and auditable way, Phase 3 adopts a Three-Horizon Model.

In this study, the Three-Horizon Model is not used as a planning framework, investment staging tool, or decision gateway. It is used exclusively as a cost-behaviour classification system, designed to distinguish fundamentally different escalation environments over time.

Each horizon represents a distinct escalation regime characterised by technology maturity, supply chain depth and competitiveness, delivery repeatability, and the degree of uncertainty surrounding future deployment conditions. They are differentiated by how costs behave, rather than by fixed calendar dates or planning milestones.

Technology Characteristics:

- **Horizon 1** – Predictable Escalation Environment
  - Horizon 1 represents conditions where technologies are mature and deployment pathways are well established. Escalation behaviour is dominated by general inflation, labour and materials market conditions, and delivery congestion.
  - Technologies in Horizon 1 are typically nth-of-a-kind, with stable, benchmarkable escalation behaviour suitable for conventional treatment within Class 5 cost estimates.
- **Horizon 2** – Transitional Escalation Environment
  - Horizon 2 captures the transition between emerging and established deployment. Escalation behaviour reflects improving but incomplete technology maturity, limited supplier competition, evolving design standards, and shallow supply chains.
  - Escalation outcomes are sensitive to commitment timing and require conditional or staged treatment.
- **Horizon 3** – Uncertain Escalation Environment
  - Horizon 3 represents immature technologies with unproven deployment pathways. Escalation behaviour is dominated by first-of-a-kind effects, uncertain learning curves, and policy or regulatory uncertainty.
  - Cost estimates in this horizon are exploratory and used for directional comparison rather than prediction.

Table 2-1 Three Horizon – Technology Adoption

Horizon	Year	Technology	Purpose	Description	Focus
H1	2025 - 2030	Mature	Modernise	Technologies already proven internationally and locally.	Capacity relief, stability improvement, deferral of major CAPEX.
H2	**2030 - 2040**	**Emerging**	**Transition**	Near commercial or early entry into market.	Step-change in controllability, reduced corridor constraints, reduced line footprints.
H3	**2040 - 2060**	**Transformational**	**Export**	Technologies expected to mature over the next 15–30 years.	Offshore wind integration, meshed HVDC, superpower export capability.

Each horizon reflects the predictability of cost outcomes, the balance between inflation-driven and maturity-driven escalation, and the degree to which learning effects can reasonably be assumed.

2.1 Horizon 1 – Mature Deployable Technologies (2025–2030)

These technologies are commercially proven, widely deployed internationally, and immediately applicable to New Zealand's transmission challenges. They offer high impact with low deployment risk and form the foundation of near-term capacity relief, stability enhancement, and operational resilience and include such technologies as:

2.1.1 High-Temperature Low-Sag (HTLS) Conductors

HTLS conductors—including ACCC, ACSS, INVAR, and GAP-type—enable significant thermal rating increases without full tower replacements. Their ability to double or nearly double circuit ampacity makes them ideal for constrained 220 kV and 110 kV corridors.

In New Zealand, HTLS is a particularly strong fit for:

- Upper South Island stability corridors
- Manawatu–Wellington reinforcement routes
- Christchurch load-growth corridors
- Any location where consenting new lines is challenging

HTLS provides a rapid, minimally intrusive method to increase transfer capacity while deferring major capital programs.

2.1.2 FACTS Devices (SVC, STATCOM, TCSC, PST)

FACTS technologies provide fast, controllable reactive power, voltage support, and power-flow management. In networks with high renewable penetration—such as New Zealand's—FACTS can be the difference between a stable and unstable system under contingency conditions.

Applications include:

- STATCOMs to support NI load centres during low-inertia periods
- TCSC to increase south-to-north transfer on existing HVAC paths

- PSTs to balance flows across parallel circuits and reduce overload risk
- FACTS devices offer a comparatively low-CAPEX alternative to new transmission lines when addressing thermal overloads driven by power-flow imbalance rather than raw capacity.

2.1.3 Digital Substations (IEC 61850-9-2)

Digital substations replace aging copper signalling with fibre-optic sampled values, dramatically improving reliability, asset monitoring, protection speed, and resilience. They also significantly reduce secondary system failure risk—currently a growing concern in New Zealand's aging substation fleet.

Digital platforms enable:

- Faster protection response
- Improved fault location
- Easier future automation
- Lower long-term maintenance costs

Serious consideration should be given to this technology for any substation rebuild or major augmentation from 2026 onward.

2.1.4 Composite Poles and Compact Towers

Composite poles and modern compact lattice towers offer lower visual and environmental footprints which may improve planning and approvals. Cost benefits may also be gained due to the reduction in foundation requirements typically associated with this technology. This in turn can improve seismic performance and more efficient installation.

These advantages make them ideal for rebuilding constrained corridors, especially in:

- Wellington's earthquake-sensitive zones
- Canterbury and alpine regions
- Densely populated or environmentally sensitive areas

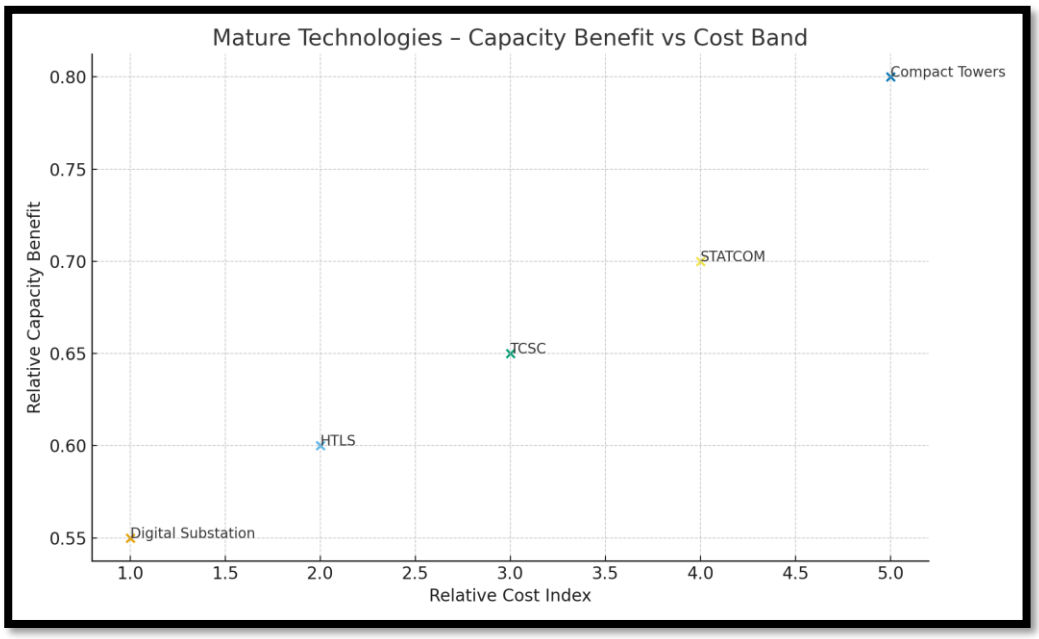
2.1.5 Gas-Insulated Lines (GIL)

GIL offers extremely high-power density and is suitable for deep urban entry where overhead lines are not feasible. While higher cost than overhead alternatives, GIL reduces fire risk, easement conflicts, and visual impact.

GIL applications in New Zealand include:

- Future Auckland CBD reinforcement
- Underground entry into Wellington load centres

Figure 2-1 Horizon 1 - Mature Technologies Behavioural Map (H1)



2.1.6 Horizon 1 Summary

These technologies address immediate bottlenecks and stability constraints with minimal consenting difficulty and high technical maturity. Horizon 1 forms the “modernise first” foundational stage of New Zealand’s transmission transformation pathway.

2.2 Horizon 2 – Emerging Technologies (2030–2040)

Horizon 2 technologies are those that are currently in advanced pilot stages, entering early commercial deployment globally, or are expected to reach widespread commercial availability between 2030 and 2040. These technologies represent the next major step-change for New Zealand’s grid, offering increased controllability, reduced environmental footprint, and the ability to create hybrid architectures that better serve long-term national needs.

2.2.1 Hybrid AC/DC Transmission Lines

Hybrid AC/DC transmission uses a shared tower or shared corridor to host both HVAC and HVDC circuits. This dramatically increases power density while minimising environmental and consenting impacts.

Why it matters for NZ:

- New Zealand’s long, narrow corridors are geographically constrained.
- Hybrid lines allow future DC upgrades without requiring new easements.
- A hybrid approach provides dual-mode flexibility—AC for local grid injection, DC for bulk long-range transfer.

Applications:

- North Island backbone reinforcement (central NI)
- Future-proofing corridors expected to host offshore wind injections
- Long SI–NI reinforcement where easements are politically difficult

2.2.2 Clean-Air 400 kV GIS (SF_6-Free)

Global pressure to eliminate SF_6 has accelerated development of clean-air GIS systems suitable for 220 kV–400 kV operation. By 2030–2035, multiple manufacturers expect full commercial availability of 400 kV clean-air switchgear.

Why it matters for NZ:

- Enables future 400 kV development without greenhouse gas limitations.
- Reduces substation footprint by 60–75%, enabling urban or constrained builds.
- Provides seismic resilience improvements compared with traditional AIS yards.

Applications:

- Future 400 kV receiving nodes near HVDC terminals
- Future offshore wind reception substations

2.2.3 Grid-Forming Inverter (GFM) Clusters

Grid-forming inverters represent a fundamental shift in system stability capability. Unlike grid-following inverters, GFM devices establish voltage and frequency reference, contributing synthetic inertia and acting much like a synchronous machine.

Why it matters:

- Hydro-based stability will decline as hydrology shifts and renewables grow.
- High wind and solar penetration require stronger inverter-based stability.
- GFM clusters can stabilise weak networks and black-start regions.

Applications:

- Future offshore wind developments (Taranaki, SI east coast)
- Renewable corridors where system strength is marginal
- Weak-grid NI development zones

2.2.4 Distributed FACTS and Edge Power Control

Distributed FACTS systems include pole-mounted or feeder-level D-STATCOMs, power electronics voltage regulators, and smart line compensation.

Why it matters:

- Electrification of transport will push peak loads locally.
- Avoids unnecessary transmission upgrades for highly localised constraints.
- Stabilises voltage in distribution–transmission interface zones.

Applications:

- Auckland electrification
- Hamilton growth zone
- Wellington–Hutt Valley load pockets

2.2.5 Modular HVDC Converter Stations

By the early 2030s, HVDC technology is expected to shift toward more modular, containerised converter designs similar to modular data centers. This reduces footprint, installation time, and construction cost.

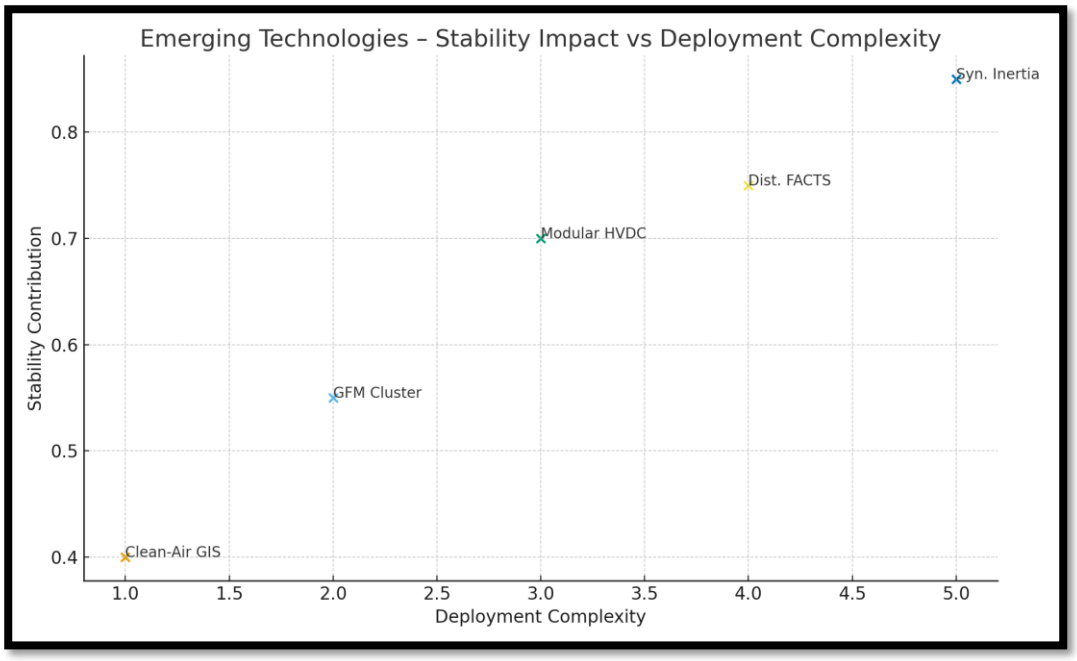
Why it matters for NZ:

- The HVDC link will require staged incremental expansion by 2040.
- Modular HVDC allows partial upgrades without full site rebuilds.
- Supports multi-terminal expansions (Horizon 3) and offshore onshore nodes.

Applications:

- HVDC North and South terminal expansions
- Offshore wind landing hubs

Figure 2-2 Horizon 2 - Emerging Technologies Behavioural Map (H2)



2.2.6 Horizon 2 Summary

Horizon 2 introduces technologies that offer major structural improvements to New Zealand's future grid. These technologies reduce long-term CAPEX, improve stability, prepare the grid for offshore wind, increased electrification, and the transition to a hybrid AC/DC backbone.

2.3 Horizon 3 – Transformational Technologies (2040–2060)

Horizon 3 technologies reflect the landscape expected to emerge once major global electrification, offshore wind expansion, and HVDC standardisation reach maturity. These technologies are not speculative—they are in advanced R&D programs today, with clear paths to commercial deployment within the Te Kanapau horizon. Technologies like those listed below arguably find their relevance to New Zealand as being exceptionally high due to its islanded system, stability challenges, and perhaps even a long-term possibility as an energy exporter.

2.3.1 Multi-Terminal HVDC and HVDC Meshed Grids

Multi-terminal HVDC represents the next logical evolution of point-to-point VSC links. By the 2040s, Europe and parts of Asia are expected to operate HVDC meshes for offshore wind and regional power balancing.

Why it matters for NZ:

- The existing ±350 kV HVDC will require major reinvestment mid-century.
- Multi-terminal topologies reduce single-point-of-failure vulnerability.

- Ideal architecture for offshore wind integration (Taranaki, SI east coast).
- Reduces NI–SI transfer risk and significantly improves resilience.

Applications:

- HVDC link rebuild (2040–2050).
- Offshore HVDC hub interconnection.
- North–South energy export backbone.

2.3.2 High-Temperature Superconducting (HTS) Corridors

Superconducting cables (HTS, 1G/2G) offer extremely high-power density—up to 5–10× standard HVAC or HVDC lines. While not suitable for entire networks, they are ideal for highly constrained urban corridors.

Why it matters for NZ:

- Wellington and Auckland have deeply constrained entry corridors.
- HTS eliminates sag, fire risk, and easement needs.
- Perfect for last-mile injection where overhead is impossible.

Applications:

- Wellington CBD reinforcement (2045+).
- Auckland high-density entry (post-2040).

2.3.3 Autonomous Transmission Inspection & Maintenance Systems

By the 2040s, line inspection, substation condition monitoring, and vegetation management will rely on robotics, drones, and AI vision systems as standard practice.

Why it matters:

- Workforce pressures in NZ are forecasted to intensify.
- Robotics reduce safety incidents and OPEX.
- Autonomous diagnostics improve asset longevity.

Applications:

- Full-fleet O&M modernisation from 2040 onwards.

2.3.4 Synthetic Stability Layer (AI-Orchestrated Inertia & System Strength)

As synchronous machine penetration declines, global grids will increasingly use an “AI stability layer” that coordinates synthetic inertia, grid-forming converters, and line controls in real time.

Why it matters for NZ:

- The NI and SI both face future low-inertia challenges.
- Hydro can no longer carry the entire stability burden.
- AI coordination improves grid strength far beyond single-device SVC/STATCOM approaches.

Applications:

- Regions with high renewable penetration.
- System-wide stability frameworks post-2040.

2.3.5 Flexible Submarine HVDC "Energy Highways"

Conceptually similar to the European North Sea grid, flexible submarine HVDC enables dynamic routing of bulk power over long distances with high reliability.

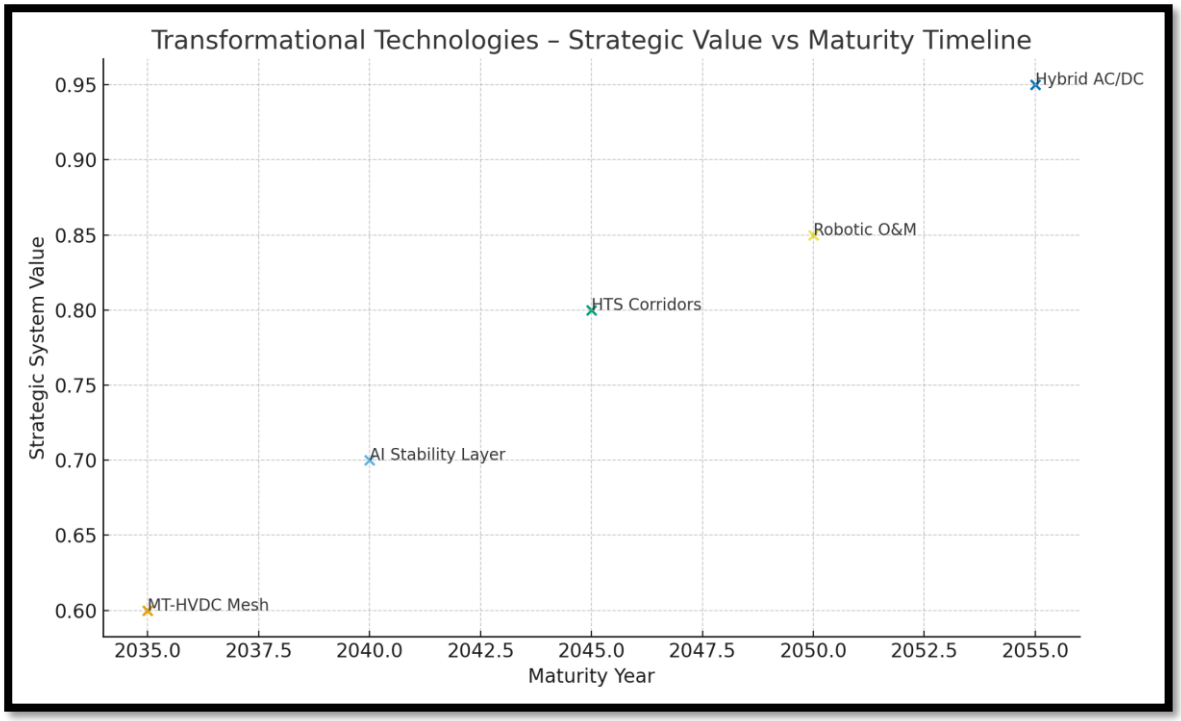
Why it matters for NZ:

- Aligns with NZ's potential future role as a net power exporter.
- Useful for connecting offshore wind developments.
- Provides redundancy for HVDC outages.

Applications:

- Offshore wind integration (deep-water concept).
- Long-term energy export pathways.

Figure 2-3 Horizon 3 - Transformational Technologies Behavioural Map (H3)



2.3.6 Horizon 3 Summary

Horizon 3 is the architecture of NZ's 2050–2060 system: resilient, flexible, digitally orchestrated, and capable of supporting offshore wind, full electrification, and potential energy exports. These technologies transition New Zealand from a reinforced HVAC/HVDC system into a hybrid AC/DC, multi-terminal, stability-optimised future grid.

2.4 Horizon Transitions Inflection Points and Escalation Inflection Points

Escalation behaviour does not improve simply with the passage of time. Within the Three-Horizon framework, transitions between escalation regimes are treated as conditional rather than ccurring only when evidence demonstrates a material change in cost behaviour.

This section outlines as how escalation inflection points are identified, how premature de-escalation is avoided, and how staged commitment moderates' escalation exposure over long planning horizons.

2.4.1 Escalation Inflection Points and Evidence-Based Transitions

Inflection points represent moments where the escalation environment for a technology change materially.

Such inflection points arise through demonstrable evidence, including:

- improvements in technology maturity,
- repeat deployment and standardisation,
- increased supply chain competition,
- stabilised benchmark cost data,
- or verified learning effects.

Horizon transitions are therefore evidence-led rather than time-led. A technology does not progress to a lower escalation regime simply because time has passed; it does so only when observable indicators show that cost uncertainty and escalation sensitivity have reduced.

This approach ensures that escalation assumptions remain grounded rather than optimism.

2.4.2 Avoiding Premature De-Escalation

A core function of the horizon framework is to prevent premature de-escalation.

Where uncertainty persists — whether due to limited deployment history, bespoke design requirements, or constrained supply chains — escalation assumptions remain conservative, even if technologies appear promising.

This discipline avoids the risk of embedding optimistic assumptions too early in the cost model and preserves the credibility of long-horizon estimates.

2.4.3 Staged Commitment and Escalation Moderation

Staged commitment plays a central role in managing escalation exposure.

By allowing projects to progress through defined stages of commitment, uncertainty can be reduced progressively and learning effects realised before full capital exposure occurs.

Under this approach:

- early project components may remain within higher escalation regimes,
- later stages benefit from reduced escalation sensitivity as evidence accumulates,
- and escalation exposure is actively managed rather than absorbed.

This enables escalation moderation without relying on blanket de-escalation assumptions.

2.4.4 Relationship to First-of-a-Kind and Repeat Deployment Effects

Staged commitment is particularly effective in managing first-of-a-kind (FOAK) exposure.

Initial deployments often carry elevated escalation sensitivity due to immaturity, bespoke design, and limited supply chain depth.

As technologies transition toward repeat deployment, learning effects and standardisation reduce escalation volatility.

The horizon framework explicitly captures this transition by:

- retaining conservative escalation treatment during FOAK phases, and
- allowing de-escalation only when repeat deployment evidence supports it.

This ensures that learning effects are recognised without being assumed.

2.4.5 Learning Effects and the Role of Experience Curves

Observed learning effects in infrastructure and energy technologies are often described using experience curve relationships, such as ***Wright's Law**, where unit costs tend to decline as cumulative deployment increases.

Rather than applying generic experience curve reductions prospectively, the framework requires that learning effects be demonstrated through:

- repeat deployment,
- standardised designs,
- stabilised supply chains, and
- benchmark cost convergence.

Only when these conditions are observed does the framework permit a transition toward reduced escalation sensitivity.

This ensures that experience curve concepts inform escalation moderation without introducing speculative cost reductions or optimistic bias.

***Wright's Law –** Is a broadly understood economic principle which posits that for many technologies, each doubling of cumulative global production results in a predictable reduction in unit cost, typically expressed as a "learning rate." In electricity networks, technologies such as HVDC VSC converters, STATCOMs, GIS switchgear, and digital protection systems display consistent learning-curve behaviour as manufacturing scale increases. This makes Wright's Law a robust basis for Horizon 2 estimating, where costs decline gradually (e.g., 0.5–1.5% annually) as technology matures, standardises, and global deployment accelerates.

2.4.6 Summary

Taken together, inflection points, staged commitment, and evidence-based transitions form a coherent mechanism for managing escalation and de-escalation across long planning horizons.

Rather than treating escalation as a static input, the Three-Horizon framework allows escalation exposure to be shaped deliberately, reflecting maturity progression, deployment evidence, and commitment strategy.

Whilst this report focusses on proving a robust framework through technical due diligence and analysis to provide Transpower with an escalation model stepped in empirical evidence and usable through the TEES platform.

Addendum 1 of this report takes the horizon framework on a theoretical journey to demonstrate how it can add value throughout a project planning lifecycle by problem mapping it to several plausible real-life network constraints.

3 Quantitative Construction of Escalation Inputs

3.1 Purpose and Role of This Section

The purpose of this section is to convert the entire study's qualitative findings (technology maturity, architecture complexity, scale/repetition effects, and observed market behaviour) into a complete, auditable numerical input set for the escalation equation used in Sections 4–5.

This will provide **a single consolidated 'parameter register'** that fixes the baseline values and the allowable ranges that TEES is permitted to apply when generating escalation curves.

3.2 What must be numerically defined (baseline metrics required by the model)

- **E_base** – base escalation anchor (real terms) that represents the neutral long-run escalation setting before technology-specific behaviour modifiers are applied.
- **H_factor** – horizon behaviour factor translating maturity state (H1/H2/H3) into a bounded modifier consistent with observed behaviour bands.
- **A_factor** – architecture & maturity factor translating system complexity/standardisation into a bounded modifier.
- **S_factor** – scale & repetition factor translating programme scale/standardisation/learning benefits into a bounded modifier.
- **E_final** – annual escalation rate produced by the equation (used to generate annual multipliers).

3.3 Parameter 1: Base escalation anchor (E_base)

E_base is the neutral, long-run, real-terms escalation anchor used for regulated transmission planning. It is not CPI, not PPI, and not a market forecast. It is a modelling baseline that is deliberately adjusted by the technology behaviour factors (H, A, S).

3.3.1 Evidence streams used

- **Phase 2 escalation analysis**: synthesis of long-run escalation outcomes observed across comparable regulated transmission programmes.
- **International benchmark triangulation:** regulated transmission benchmarks (e.g., UK/Ofgem-style regimes, Australian regulated network experience, Canadian utilities/Hydro-Québec-type comparators) as compiled in the study.
- **Consistency check against Behaviour Differential:** ensures the anchor, once modified, can reproduce the empirically observed escalation bands without forcing unrealistic factor values.

3.3.2 Conversion into a numerical value (simple equation)

The study identifies a conservative neutral long-run real escalation range suitable for planning. The anchor is set as the central tendency of that range:

$$E_base = (E_low + E_high) / 2$$

Where (example, as used in this report): E_low = 3.0% and E_high = 4.0% (real terms) → E_base = (3.0% + 4.0%) / 2 = 3.5% (real terms).

Why this matters: by making the anchor a central tendency (rather than an optimistic or conservative extreme), any bias is pushed into explicit behaviour factors where it can be audited, challenged, and updated.

3.4 Parameter 2: Horizon behaviour factor (H_factor) – H1 mature / H2 emerging / H3 transformational

H_factor translates the Three-Horizon classification into a bounded numerical modifier that reflects lifecycle-dependent escalation behaviour. It is the mechanism that prevents a single annual rate from being used across all technologies.

3.4.1 Evidence streams used

- **Horizon classification logic:** maturity, deployment evidence, and architectural stability assessments from Section 2 of the framework and the technology supporting document.
- **Behaviour Differential table:** empirical bounds for materials/labour/shipping volatility, learning curves, and macro drift (used to set plausible ranges for H_factor by horizon).

3.4.2 Conversion into a numerical value (simple equation)

The study defines a horizon-specific escalation band (in real terms) and then converts it into an H_factor using the base anchor:

$$H_factor = E_horizon / E_base$$

Where E_horizon is the representative annual escalation rate for that horizon (selected as the midpoint of the horizon band).

Using E_base = 3.5%, the representative horizon rates and implied H_factors are:

Table 3-1 Three Horizon H_Factor

Horizon	Representative E_horizon (real p.a.)	Calculation	Resulting H_factor
H1 (Mature/Known)	3.0%	0.030 / 0.035	0.857
H2 (Emerging)	4.5%	0.045 / 0.035	1.286
H3 (Transformational)	5.5%	0.055 / 0.035	1.571

Note: these representative values **are not forecasts**. They are planning anchors that (a) sit inside the empirically observed behaviour envelope and (b) can be updated through governance without changing the model structure.

3.5 Parameter 3: Architecture & maturity factor (A_factor)

A factor that captures the escalation consequence of system complexity and standardisation. More bespoke, tightly coupled, or supply-chain-constrained architectures attract an uplift; highly standardised modular architectures attract no uplift.

3.5.1 Evidence streams used

- **Architecture assessment charts and maturity mapping**: in the Technology Supporting Document (architecture complexity, modularity, interface burden, supplier concentration).

- **Qualitative architecture logic**: in the framework (why complex systems suffer early-stage inefficiencies and pricing power).

3.5.2 Conversion into a numerical value (simple mapping)

A_factor is assigned via a bounded mapping:

Table 3-2 Three Horizon A_Factor

Architecture type	A_factor	How derived / what it means
Highly standardised, modular	1.00	No complexity uplift; standard interfaces; wide supplier base.
Hybrid / partially standardised	1.10	Moderate complexity uplift; non-standard interfaces; partial supplier concentration.
Bespoke / novel / high interface burden	1.20–1.25	Higher uplift; bespoke engineering, constrained OEMs, higher integration risk.

3.6 Parameter 4: Scale & repetition factor (S_factor)

S_factor reflects learning and repetition benefits achieved through programme scale (repeat design, repeated procurement lots, repeated construction methods). It moderates escalation rather than acting as a primary driver.

3.6.1 Evidence streams used

- Deployment evidence and programme sequencing assumptions (repeat build effects).
- Learning curve references (e.g., Wright's Law) used as a behavioural analogue for repetition efficiency.

3.6.2 Conversion into a numerical value (simple equation)

S_factor is assigned as a moderation percentage converted to a multiplier:

$$S_factor = 1 - m$$

Where m is the assumed moderation fraction attributable to repetition (e.g., 5% moderation → S_factor = 0.95).

3.7 Consolidated escalation model parameter register

This table is the single source of truth for the model inputs. Each value is traceable to an evidence stream and convertible via the simple calculations shown above.

Table 3-3 Consolidated Parameter Register

Parameter	Symbol	Fixed value / selected central	Evidence stream(s)	Conversion / calculation
Base escalation anchor	E_base	3.5% real p.a.	Phase 2 escalation synthesis; international	E_base=(E_low+E_high)/2; (3.0%+4.0%)/2

			regulated transmission benchmarks	
Horizon behaviour factor – mature	H_factor(H1)	0.857	Horizon classification + Behaviour Differential bounds	H=E_horizon/E_base; 3.0%/3.5%
Horizon behaviour factor – emerging	H_factor(H2)	1.286	Horizon classification + Behaviour Differential bounds	H=E_horizon/E_base; 4.5%/3.5%
Horizon behaviour factor – transformational	H_factor(H3)	1.571	Horizon classification + Behaviour Differential bounds	H=E_horizon/E_base; 5.5%/3.5%
Architecture factor	A_factor	1.00 / 1.10 / 1.20–1.25	Technology architecture assessment	Bounded mapping by architecture type
Scale & repetition factor	S_factor	0.95–1.00 (typical)	Programme scale & learning evidence	S=1−m (m=0–5% typical moderation)

4 Escalation Equation – Playbook and Worked Examples

Section 4 provides Transpower with a practical 'how to' so that the model can be applied consistently, without reverting to a single-rate habit. Section 4 uses the parameter register (Section 3) and demonstrates the equation form, why it is structured this way, and how it produces annual multipliers for each horizon.

4.1 Recap – the fixed numerical inputs (from Section 3)

The following are fixed baseline inputs for transmission technology escalation modelling (real terms):

- **E_base** = 3.5% p.a. (real terms).
- **H_factor** (H1 mature) = 0.857
- **H_factor** (H2 emerging) = 1.286
- **H_factor** (H3 transformational) = 1.571
- **A_factor** = 1.00 (standardised) / 1.10 (hybrid) / 1.20–1.25 (bespoke/novel).
- **S_factor** = 0.95–1.00 (depending on programme repetition).

4.2 Equation form (and why multiplicative)

The model expresses annual real escalation as a base anchor modified by bounded behaviour factors:

$$\mathbf{E_final = E_base \times H_factor \times A_factor \times S_factor}$$

This structure keeps the model proportional, bounded, and auditable. Behaviour modifiers act on a single neutral anchor rather than becoming independent escalation 'adders' that can double count or drift beyond empirical limits.

If the equation were additive (e.g., E_final = E_base + ΔH + ΔA + ΔS), small judgement changes would stack linearly and can easily exceed the empirical behaviour envelope. The multiplicative form instead preserves relativity: an uplift affects a larger base more than a smaller base, and moderation effects scale appropriately.

4.3 Full equation with numerical values – horizon archetypes

To prevent misuse, we provide three archetype 'ready-to-use' horizon equations (standard architecture, typical repetition). These are the basis of the H1/H2/H3 'Golden Multiplier' tables in Section 5.

H1 (Mature/Known): E_final = 0.035 × 0.857 × 1.00 × 0.95 = 2.85% p.a. (real)

H2 (Emerging): E_final = 0.035 × 1.286 × 1.00 × 0.95 = 4.28% p.a. (real)

H3 (Transformational): E_final = 0.035 × 1.571 × 1.00 × 0.95 = 5.22% p.a. (real)

4.4 When A_factor and S_factor change (technology-specific curves)

Within any horizon, technologies can legitimately deviate from the archetype curve due to architecture complexity (A_factor) and/or programme repetition (S_factor). TEES should therefore:

- Assign the horizon (H1/H2/H3) based on the framework's classification rules.
- Assign A_factor based on the technology architecture assessment (standardised/hybrid/bespoke).
- Assign S_factor based on how repeatable the build is (programme scale, lotting, standard design reuse).
- Calculate E_final and generate the annual multiplier series from the base year.

This preserves the three-horizon discipline while still allowing technology-specific realism.

4.5 How do these parameters connect to the 'golden' annual multiplier tables

The annual multiplier tables provided within section 5 of this report are not separate assumptions; they are the 'true' results from this studies entire analytical and scenario-based research and testing. Therefore, we have built these as fully usuable and applicable for Transpowers needs for technology escalation.

The tables are a compounded output of E_final applied each year from the base year:

$$\text{Multiplier}(y) = \Pi_{k=1..(y-\text{base_year})} (1 + E_{final})$$

Where E_final is produced by the equation in Section 6 and differs by horizon via H_factor (and may differ by technology via A_factor and S_factor).

Therefore: (a) each horizon can have its own multiplier table, and (b) TEES can generate technology-specific curves by applying the appropriate A_factor and S_factor within that horizon.

5 TEES Integration – Three-Horizon Implementation, Outputs, and Governance

This section now describes how Transpower could implement the three-horizon escalation model inside TEES without collapsing the approach into a single rate.

All escalation outcomes presented in this section are derived from the governing equation defined in Section 4:

E_final = E_base × H_factor × A_factor × S_factor

Where E_base is the neutral long-run structural escalation anchor (3.5% p.a., real, 2023 base year), and the remaining factors adjust escalation behaviour according to technology horizon, architectural complexity, and programme learning effects.

TEES should store three horizon curves as defaults (H1/H2/H3), and then apply technology-specific adjustments via A_factor and S_factor when warranted.

5.1 TEES configuration concept

- Create three 'default escalation libraries' in TEES: H1 (mature), H2 (emerging), H3 (transformational).
- For each library, store: E_base, horizon label, default H_factor, default A_factor (1.0), default S_factor (0.95), resulting E_final, and the annual multiplier table (2025–2060).
- For specific technologies, TEES should override A_factor and/or S_factor (not E_base) and regenerate the curve.

5.2 Pre-calculated annual multiplier tables (2025–2060)

To support consistent and repeatable application within TEES, the escalation equation is pre-applied to generate horizon-specific 'Golden Multiplier Tables'. Each table represents the cumulative escalation multiplier relative to the base year for a representative technology within a given horizon.

These tables are horizon-bounded reference artefacts and must only be applied to assets or cost blocks that genuinely exhibit the characteristics of that horizon.

These tables are the 'golden' multipliers, pre-calculated for Transpowers ease of use when forecasting escalation costs for technology. They are generated by compounding (1 + E_final) each year from 2025 (multiplier = 1.000).

Default assumptions have been applied using the same analytical and scenario-based analysis presented within the suite of reports in response to Transpowers Phase 3 brief and these can be seen in the table below.

Table 5-1 Golden Multiplier Table Assumptions

Golden Multiplier (H1)	Golden Multiplier (H2)	Golden Multiplier (H3)
• E_base = 3.5% p.a. (real, 2023 base year)	• E_base = 3.5% p.a. (real, 2023 base year)	• E_base = 3.5% p.a. (real, 2023 base year)

• H_factor > 0.85 (implicit in result) • A_factor = 1.00 (standardised reference assumption) S_factor = 0.95 (modest learning effects)	• H_factor > 1.28 (defining distinction between H1 & H2) • A_factor = 1.00 (standardised reference assumption) S_factor = 0.95 (modest learning effects)	• H_factor > 1.0 (early-stage escalation pressure) • A_factor = 1.00 (standardised reference assumption) S_factor = 0.95 (modest learning effects)

5.2.1 H1 – Golden Multiplier (Mature/Known)

Default assumptions: Result with an **E_final=2.85% p.a.**

Table 5-2 H1 – Golden Multiplier

Year	Multiplier	Year	Multiplier
2025	1.000	**2048**	1.908
2026	1.028	**2049**	1.963
2027	1.058	**2050**	2.019
2028	1.088	**2051**	2.076
2029	1.119	**2052**	2.135
2030	1.151	**2053**	2.196
2031	1.184	**2054**	2.259
2032	1.217	**2055**	2.323
2033	1.252	**2056**	2.389
2034	1.288	**2057**	2.457
2035	1.324	**2058**	2.527
2036	1.362	**2059**	2.599
2037	1.401	**2060**	2.673
2038	1.441		
2039	1.482		
2040	1.524		
2041	1.568		
2042	1.612		
2043	1.658		
2044	1.705		
2045	1.754		
2046	1.804		
2047	1.855		

5.2.2 H2 – Golden Multiplier (Emerging)

Default assumptions: A Result with an **E_final=4.38% p.a.**

Table 5-3 H2 – Golden Multiplier

Year	Multiplier	Year	Multiplier
2025	1.000	**2046**	2.409
2026	1.043	**2047**	2.512
2027	1.087	**2048**	2.620
2028	1.134	**2049**	2.732
2029	1.182	**2050**	2.848
2030	1.233	**2051**	2.970
2031	1.286	**2052**	3.097
2032	1.341	**2053**	3.230
2033	1.398	**2054**	3.368
2034	1.458	**2055**	3.512
2035	1.520	**2056**	3.662
2036	1.585	**2057**	3.819
2037	1.653	**2058**	3.982
2038	1.723	**2059**	4.152
2039	1.797	**2060**	4.330
2040	1.874		
2041	1.954		
2042	2.038		
2043	2.125		
2044	2.216		
2045	2.310		
2046	2.409		

5.2.3 H3 – Golden Multiplier (Transformational)

Default assumptions: Result with an **E_final=5.22% p.a.**

Table 5-4 H3 – Golden Multiplier

Year	Multiplier	Year	Multiplier
2025	1.000	**2043**	2.501
2026	1.052	**2044**	2.631
2027	1.107	**2045**	2.769
2028	1.165	**2046**	2.913

2029	1.226	**2047**	3.065
2030	1.290	**2048**	3.226
2031	1.357	**2049**	3.394
2032	1.428	**2050**	3.571
2033	1.503	**2051**	3.758
2034	1.581	**2052**	3.954
2035	1.664	**2053**	4.161
2036	1.751	**2054**	4.378
2037	1.842	**2055**	4.607
2038	1.939	**2056**	4.847
2039	2.040	**2057**	5.101
2040	2.146	**2058**	5.367
2041	2.258	**2059**	5.647
2042	2.376	**2060**	5.942

5.3 How to use H1/H2/H3 together on a single project

A project often contains a mixture of technologies. The correct application is to split the estimate into cost components by horizon (and by technology where required), apply the relevant multipliers, then recombine.

Total escalated cost(y) = Σ_i [BaseCost_i × Multiplier_{horizon(i), tech(i)}(y)]

Example:

- H1 may cover standard AIS/GIS bays, conventional OHL structures, and mature protection/control.
- H2 may cover emerging HVDC VSC platforms in the local context, novel harmonic mitigation stacks, or new digital substation rollouts.
- H3 may cover transformational architectures (e.g., multi-terminal HVDC, large offshore grid hubs, grid-forming system-dominated controls) where supply chain and integration risk is materially higher.

This approach prevents ‘one-rate-for-everything’ misuse while keeping TEES operation simple: choose horizon, optionally adjust A/S, apply curve.

5.3.1 Why Multi-Horizon Application Is Required

Real transmission projects rarely comprise a single technology maturity state. A typical Transpower project may include mature, emerging, and transformational technologies. Applying a single escalation rate would incorrectly assume uniform cost behaviour across fundamentally different technology states. The Three-Horizon Model avoids this simplification.

5.3.2 Principle of Horizon Segmentation

Project costs must be segmented by technology horizon rather than by project phase. Each cost element is assigned to a horizon using the maturity, architecture, and benchmarking analysis documented in Sections 3 and 4 of this report and the Technology Supporting Report.

This produces three cost pools:

- **H1** – Mature / Established
- **H2** – Emerging / Scaling
- **H3** – Transformational / Pre-commercial

5.4 Worked Example – Mixed-Horizon Transmission Project

The escalation multiplier derived below **applies only to the technology cost portion of the project scope.** This includes primary plant, specialist systems, and technology-dependent components classified under Horizon 1 (Mature), Horizon 2 (Emerging), and Horizon 3 (Transformational) technologies.

It explicitly excludes non-technology cost elements such as civil works, bulk earthworks, buildings, conventional construction labour, enabling works, owner's costs, and non-specialist balance-of-plant items. These cost elements are to be escalated separately using standard construction or labour indices, combined with the Three-Horizon Adoption Model and consistent with Transpower's established TEES practices.

Table 5-5 Worked Example Input Assumptions

Input Assumption	Value
Base year	**2025**
Target delivery year	**2036**
(Cw1) Technology mix - Horizon 1 (Mature)	**45%** proportionate to the volume of use per baseline cost for the project
(Cw2) Technology mix - Horizon 2 (Emerging)	**28%** proportionate to the volume of use per its baseline cost for the project
(Cw3) Technology mix - Horizon 3 (Transformational)	**27%** proportionate to the volume of use per its baseline cost for the project
***H1** multiplier (2036)	**1.362**
***H2** multiplier (2036)	**1.585**
***H3** multiplier (2036)	**1.751**

***These values have been taken straight from the Horizon Golden Multiplier tables in this report.**

5.5 Blended Technology Escalation Calculation

The blended technology escalation multiplier is calculated as a weighted average of the three horizon-specific multipliers, based on the proportion of technology expenditure falling within each horizon:

$$M_2036 = (Cw1 \times H1) + (Cw2 \times H2) + (Cw3 \times H3)$$

$$\mathbf{M_2036 = (0.45 \times 1.362) + (0.28 \times 1.585) + (0.27 \times 1.751)}$$

This results in a multiplier of: **M_2036 ≈ 1.53**

5.6 Interpretation

The resulting multiplier of approximately 1.53 indicates that the technology components of the project are expected to cost around 53% more in 2036 than in 2025 base-year dollars. This uplift reflects technology-specific drivers such as supply chain maturity, system complexity, learning effects, and innovation risk.

This figure must not be applied to the full project cost. Total project escalation must be constructed by combining this technology escalation with separate escalation treatments for construction, labour, and other non-technology cost categories.

This worked example is provided to demonstrate how the Three-Horizon escalation framework is applied in practice to a single transmission project containing multiple technology maturity states.

The example is intentionally simplified to focus on escalation behaviour only, not absolute project costing accuracy. All values are illustrative but are consistent with the benchmark ranges, horizon assignments, and escalation anchors established in Sections 3 to 5 of this report and the Technology Supporting Document.

5.7 Horizon Migration

Technologies may migrate between horizons as maturity increases. Escalation rates are updated prospectively using the Golden Multiplier Table while historical costs remain unchanged.

5.7.1 Practical Guidance for Transpower

1. Decompose project costs by technology.
2. Assign horizons using Section 2.
3. Apply escalation rates from the Golden Multiplier Table (Table 5.2.1).
4. Compound independently.
5. Reassign horizons only when maturity demonstrably changes.

5.8 Reference Python implementation

The code below is a reference implementation of the logic TEES should apply. It is not intended to replace TEES; it exists for transparency, repeatability, and audit.

```
from dataclasses import dataclass

@dataclass(frozen=True)

class EscalationParams:

    E_base: float   # e.g. 0.035 (3.5% real)

    H_factor: float # horizon behaviour modifier

    A_factor: float # architecture modifier

    S_factor: float # scale/repetition modifier

def annual_rate(p: EscalationParams) -> float:

    """Annual real escalation rate."""
```

```
    return p.E_base * p.H_factor * p.A_factor * p.S_factor

def multipliers(start_year: int, end_year: int, rate: float):
    """Year-by-year multiplier series, base year multiplier = 1.0."""
    out = {start_year: 1.0}
    m = 1.0
    for y in range(start_year + 1, end_year + 1):
        m *= (1.0 + rate)
        out[y] = m
    return out

# --- Default horizon curves (standardised architecture, typical repetition) ---
E_base = 0.035
A_std  = 1.00
S_typ  = 0.95
H1 = EscalationParams(E_base, H_factor=0.857, A_factor=A_std, S_factor=S_typ)
H2 = EscalationParams(E_base, H_factor=1.286, A_factor=A_std, S_factor=S_typ)
H3 = EscalationParams(E_base, H_factor=1.571, A_factor=A_std, S_factor=S_typ)
rate_H1 = annual_rate(H1)   # ~2.85%
rate_H2 = annual_rate(H2)   # ~4.28%
rate_H3 = annual_rate(H3)   # ~5.22%
mult_H1 = multipliers(2025, 2060, rate_H1)
mult_H2 = multipliers(2025, 2060, rate_H2)
mult_H3 = multipliers(2025, 2060, rate_H3)
```

5.9 Validation and governance inside TEES

To remain regulator-ready, TEES should enforce validation and governance controls:

- **Bound checks:** prevent E_final from exceeding the empirically supported envelope unless formally approved.
- **Traceability:** each curve stored with (E_base, H, A, S) and a link to the parameter register entry used.
- **Continuity:** ensure multiplier series is monotonic and free of discontinuities unless explicitly modelling a step change.
- **Annual parameter review:** update benchmark anchors and evidence, then re-issue the parameter register with version control.

- **Five-year structural review:** revisit horizon definitions and architecture classifications as industry context changes.

5.10 Failure Modes and Misapplication Risks

The Three Horizon Adoption Model has been intentionally structured to avoid several common escalation modelling failure modes observed in industry practice:

1. **Single-Rate Substitution**
   Applying a single annual escalation rate across all technologies regardless of maturity leads to systematic bias and mispricing. The horizon framework explicitly prevents this behaviour.
2. **Horizon Collapse**
   Collapsing emerging or transformational technologies into mature cost behaviour assumptions prematurely suppresses learning effects and adoption-driven cost change.
3. **Double Counting**
   Using horizon escalation outputs in addition to broader market or construction escalation risks double counting. This model is bounded strictly to technology behaviour only.
4. **Unbounded Forecasting**
   Extrapolating horizon-specific behaviour beyond plausible maturity windows can distort long-range forecasts. The model includes implicit saturation and convergence behaviour to mitigate this risk.

These failure modes reinforce why the horizon framework must be applied deliberately and within its defined scope.

5.11 Extensibility Beyond Transmission Technology

While this study applies the escalation model to transmission technology, the TEES implementation is deliberately artefact-agnostic and can be applied to other cost categories.

Addendum 1. Project Mapping (The Theoretical Outcome)

AD1.1 The Eight Core System Problems

Whilst we focused on the macro environment of global technologies our research into relevancy for New Zealand allowed us to focus on network system-constraints and a theoretical future.

This allowed us to identify eight core system constraints that if addressed may potentially unlock New Zealand and allow it to become a future **energy powerhouse.**

Key Network Constraint List:

1. North–South Transfer Limits & HVDC Congestion
2. Upper South Island Voltage Stability & Inertia Deficit
3. Christchurch Load Growth Under Urban Corridor Constraint
4. Manawatū & Central NI Thermal Constraints
5. Future Offshore Wind Landing (Taranaki & East Coast)
6. Wellington Entry Corridor Constraint
7. System Strength Decline in a High-Renewable Future
8. Deep Electrification & Load Growth (EVs, Hydrogen, Data Centres)

By using the above list of network constraints and applying our technology research as a layer across the top we found further support for our **Three-Horizon Adoption Model** to ensure Transpower succeed on their mission to solve the 'Energy Trilemma'.

In addition to this as we tested the model, we found that by simply applying a ***'Technology – Problem – Project Mapping'*** approach our Three-Horizon Adoption Model becomes a toolbox that Transpower could not only utilise to their benefit, but potentially easily integrate with their TEES platform.

AD1.2 Technology → Problem → Project Mapping

New Zealand's transmission system faces a defined set of structural constraints that cannot be solved through traditional line reinforcement alone.

The use of the Three-Horizon Technology Adoption Model provides Transpower with a robust cost forecasting toolbox when applied to some grounded assumptions of real NZ problems and sequencing issues over the long-term forecasting timeline of 2025–2060.

AD1.3 Technology Adoption Pathways

Using the Three-Horizon ideology and the constraints listed in section 5.2 we adopt a progressive yet balanced approach to unlocking the network in a practical sense.

First, we identified three core objectives that are entrenched in grounded assumptions. After this we identified the technologies that could help Transpower in achieving these core objectives in a logical pattern.

AD1.3.1 Layer 1 — Stabilise & Optimise (2025–2030)

Objective: Address near-term voltage, stability, and thermal constraints using mature, low-regret technologies.

Key Interventions:

1. HTLS reconductoring on NI/SI renewable corridors
2. STATCOMs + synchronous condensers for stability pockets
3. Digital substations + advanced protection upgrades
4. PSTs/TCSCs for power flow optimisation
5. Early GIL deployment in constrained entry points

AD1.3.2 Layer 2 — Expand & Hybridise (2030–2040)

Objective: Deploy emerging technologies that deliver step-change improvements in controllability and capacity.

Key Interventions:

1. Hybrid AC/DC reinforcement
2. 220–400 kV underground/GIL solutions
3. VSC HVDC terminals
4. Grid-forming BESS
5. Wide-Area Control Systems

AD1.3.3 Layer 3 — Transform & Enable Exports (2040–2060)

Objective: Implement transformational technologies enabling NZ to unlock offshore wind, hydrogen, and resilience.

Key Interventions:

1. Multi-terminal HVDC Backbone & Hybrid NI–SI Meshed Architecture
2. High-Temperature Superconducting (HTS) Corridors for Urban Entry Points
3. Autonomous Inspection, O&M, and AI-Driven Stability Management
4. Flexible Subsea HVDC “Energy Highway” for Offshore Wind & Export Pathways
5. Hydrogen-Ready Transmission Corridors & Industrial Decarbonisation Interfaces

The below information demonstrates how using the above assumptions the Three-Horizon Model Adopted for Technology can be extremely beneficial for project sequencing to enable a more accurate and responsible forecast of CAPEX.

The theoretical constructs below represent the canonical project types that could be assumed to be central to New Zealand’s long-term transmission planning.

Table AD.1-1 Construct vs Technology Fit

Construct	Description	Technology Fit	Notes
1. Long-Distance AC Backbone (North Island–South Island and regional)	High-capacity inter-island and intra-island corridors	400 kV AC	Strength, stability
2. HVDC Reinforcement (Existing Link Renewal)	Upgrade or replacement of existing HVDC infrastructure	VSC HVDC	Weak-grid resilience

3. Offshore Wind Collection & Landing System	Multi-gigawatt offshore injection	VSC HVDC, Multi-terminal HVDC	Future offshore zones
4. Major Renewable Node Reinforcement	Upstream capacity for 2–4 GW nodes	Hybrid AC/DC	South Island and North Island renewable-heavy areas
5. Urban Entry Reinforcement	Capacity for entry into Wellington/Auckland	GIS, GIL, HTS	Corridor constraints
6. Regional Strength Uplift	Improvement of Short-Circuit Ratio (SCR) and stability	400 kV, synchronous condensers, STATCOM, GFM	North Island pockets
7. Resilience-Driven Redundancy Paths	Establishment of alternative transfer pathways	AC and DC hybrid	Climate and earthquake resilience
8. Multi-Terminal Future Grid Preparations	DC-ready nodes and switchyards	VSC HVDC	Long-term optionality

These constructs support a “mapping card” methodology, whereby each structural issue in New Zealand’s grid is addressed by one or more constructs.

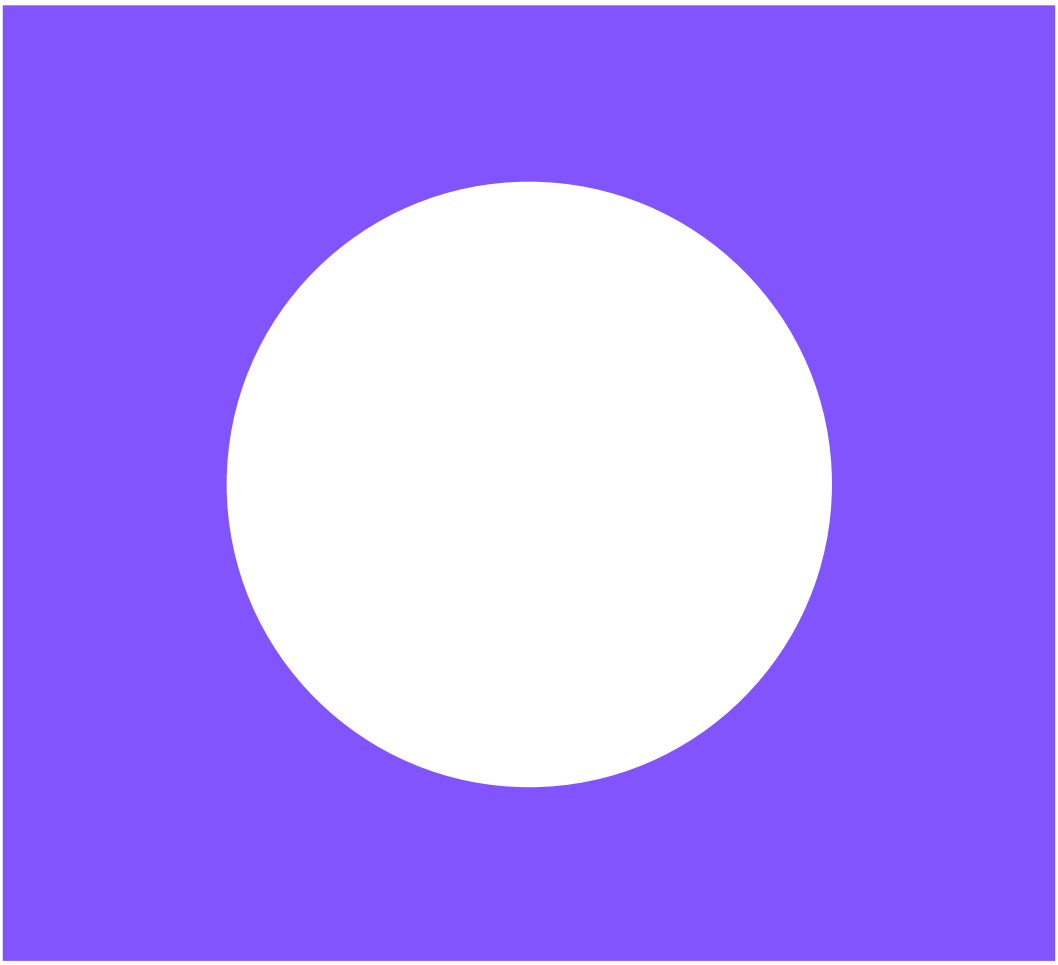
Table AD.1-2 Constraint Mapping – Linking constructs to real problems

NZ Constraint	Severity	Related Constructs	Notes
Low system strength pockets	High	1, 4, 6	North Island North, South Island South
HVDC bottleneck and ageing infrastructure	High	2, 7, 8	Existing link constraints
Urban entry limits	High	5	Wellington, Auckland
Offshore wind readiness	Medium–High	3, 8	Anticipated need for multi-terminal solutions
Corridor scarcity	High	1, 5, 7	Community acceptance
Voltage stability limitations	High	1, 4, 6	Increased sensitivity due to inverter-based generation

This mapping remains fully consistent with industry data and shows how easily one could sequence several projects (constructs) based on technology availability and maturity.

Example: Construct 1 appears across three constraints as part of a plausible solution. We know that the technology required to build the architectural infrastructure for this solution is suggested as 400kV.

Therefore, by using our Three-Horizon model we can see that this technology is assumed to sit in Horizon 1 (H1) and is therefore mature and proven into today’s market. Suggesting that

system constraints unlocked by construct 1 could be planned to be completed between 2025-2035.

However, by comparison construct 7 appears once as part of a plausible solution and this has a suggested technology of *'AC/DC Hybrid'.* This technology may be known about, however commercial viability only appears between 2035-2045 (H2-emerging). Therefore, these types of constructs may be better off planned for within this period.