Quantifying the Competition Benefits of Transmission Investment

Methodology Report

September 2025

Table of contents

Tables

Figures

Boxes

Definitions

EA	Electricity Authority
EMI	Electricity Market Interface
vSPD	virtual Scheduling, Pricing, and Dispatch
MPC	Market Power Cost
BESS	Battery Energy Storage System
VoLL	Value of Lost Load
PDC	Price Duration Curve
VRE	Variable Renewable Energy
SRMC	Short-Run Marginal Cost

Executive Summary

Transpower has engaged Castalia to develop a methodology for quantifying competition benefits from transmission investment, which is presented in this report.

Current investment analysis assumes perfectly competitive bidding and, therefore, does not consider or attempt to quantify competition benefits that can be realized through transmission investments. We understand that this issue has been considered before and not included in transmission investment decisions. However, this paper argues that the benefits of competition from transmission investment should be considered when assessing investment options, because the impacts of constrained transmission on consumers are already large due to significant wealth transfers from consumers to generators. Further, the impact on consumers will grow with time as increasing Variable Renewable Energy (VRE) penetration leads to more periods when a dispatchable generator can exercise market power in a node due to constrained transmission and a decreasing number of dispatchable generators. Finally, we believe that considering the impacts of wealth transfers on consumers is within the remit of the Electricity Authority.

Transmission investment can reduce wealth transfers by increasing competition at the constrained nodes. Our proposed methodology allows Transpower to use its existing modelling tools to directly isolate and quantify Market Power Cost (MPC) and consider how the cost changes with a specific transmission investment. By quantifying these benefits, Transpower can present clearer, consumer-focused business cases and better align the Grid Blueprint with long-term consumer interests, including lower prices for the end user.

Rationale for why Transpower should include competition benefits when considering transmission investments

There are three key reasons why Transpower should consider competition benefits when considering transmission investments:

- The Electricity Authority's (EA) primary objective is to promote competition for the long-term benefit of consumers. Reducing wealth transfers in constrained nodes directly aligns with this mandate because they arise from a lack of competition caused by grid constraints. By quantifying these benefits, Transpower can assure EA that it has considered the best interests of consumers in its investments.
- The scale of wealth transfers resulting from constrained transmission is already larger than previously thought. It will increase in the coming years due to the growing uptake of VRE, which will make periods where generators can exercise market power more frequent. This growing impact on consumer prices will make wealth transfer harder to ignore and strengthen the case for including these benefits in transmission planning now.
- Further, addressing the issue by including competition benefits in transmission investment decisions is an efficient solution. Alternatively, consumer prices are likely to rise, either nationally or regionally, to a point that invites reactive and potentially more distortionary regulatory interventions driven by political pressure.

Our approach and methodology for calculating the competition benefits of transmission investment is defined as Market Power Cost

We define **Market Power Cost (MPC)** as the additional cost imposed on consumers when generators offer above their short-run marginal cost (SRMC) and are dispatched due to being in a net pivotal position at the relevant node. It is the difference between:

- the price that would have cleared the market at the node under competitive conditions (that is, assuming all generators offer at SRMC); and
- the actual market price that clears when one or more generators bid strategically, because they are (or expect to be) net pivotal.

To calculate MPC, our methodology proposes a transparent, four-scenario modelling approach, outlined below, which compares market outcomes with and without the proposed investment.

Figure 0.1: Modelling scenario structure

	Perfect Competition	Strategic Behaviour
Constrained grid (1A/1B) *in the future*	**1A.** *SRMC bids on a future grid where the potential investment has **not** gone ahead.* **Shows:** Pre-investment hypothetical price pattern on relevant nodes with assumed perfect competition.	**1B.** *SRMC offers, but mark-ups are triggered when pivotal on a future grid where potential investment has **not** gone ahead* **Shows:** Pre-investment expected actual price pattern on relevant nodes given imperfect competition.
With the proposed investment *in the future* (2A/2B)	**2A.** *SRMC bids on a future grid where the potential investment **has been made**.* **Shows:** Post-investment hypothetical price pattern on relevant nodes with assumed perfect competition.	**2B.** *Mark-ups are triggered on a future grid where potential investments have **been made**.* **Shows:** Post-investment expected actual price pattern on relevant nodes, incorporating any improvement in competition due to the investment.

With these four outputs, we create two simple yardsticks:

- An estimate of the foreseeable future cost of market power in the relevant area of the grid **without** the proposed investment. We measure this as the difference in price outcomes between scenario 1B and scenario 1A. Let's call this Market Power Cost 1 or MPC1. MPC1 = 1B – 1A
- An estimate of the foreseeable future market power costs in the relevant area of the grid **with** the proposed new investment in place. We measure this as the difference in price outcomes between scenario 2B and scenario 2A. Let's call this MPC2. MPC2 = 2B – 2A

We can then estimate the net competition impact of the proposed investment by taking the difference between the two MPCs. The project under consideration has a net competition benefit if MPC2 is lower than MPC1 under the investment scenario—that is, if the following calculation gives a positive number: Competition benefit = (1B – 1A) – (2B – 2A).

Based on our approach, we propose a six-step methodology for calculating an MPC cost, which is then subjected to a sensitivity analysis to ensure that the results are robust. Figure 0.2 summarises our recommended process.

Figure 0.2: Summary of Process

Step 1	Determine areas with *current* grid constraints
Step 2	Identify current strategic bidding patterns in constrained areas of the grid and quantify the incremental costs to consumers relative to hypothetical SRMC bidding to calculate MPC lift
Step 3	Identify areas of future grid constraints and apply MPC uplift measure from step 2 to those areas to quantify future MPC **(MPC1)**
Step 4	Run SRMC and MPC uplift scenarios with proposed transmission investment under evaluation at a determined point in the future **(MPC2)**
Step 5	Determine the net competition impact of grid investment. **Competition impact = MPC1 – MPC2**
Step 6	Conduct a sensitivity analysis using a range of assumptions for MPC lift

Steps 1 and 2 identify where current constraints enable market power and analyse strategic bidding patterns to estimate the average associated cost to consumers. Step 3 projects where transmission constraints may create market power in the future and calculates how strategic bidding patterns will create MPC in each affected area of the grid before any transmission investments are made (MPC1). Step 4 models how the MPC for each area changes if proposed grid investments proceed (MPC2). Step 5 calculates the net competition benefit as the reduction in MPC resulting from transmission investment. Step 6 undertakes sensitivity analysis to see how the results change with a different set of scenarios and assumptions.

If Transpower accepts this methodology, the next step is to conduct a complete end-to-end test of the methodology. The results from these tests will then need to be analysed and refined. We can then use the results to create a model and process that Transpower will use to support decisions about transmission investment.

1 Introduction

Current investment analysis assumes perfectly competitive bidding and, therefore, does not consider or attempt to quantify competition benefits that can be realized through transmission investments. By quantifying these benefits, Transpower can present clearer, consumer-focused business cases and better align the Grid Blueprint with long-term consumer interests, including lower prices for the end user. We understand that this issue has been considered before and not been included in transmission investment decisions; however, this paper argues that competition benefits from transmission investment should be considered when assessing transmission investments because the impacts on consumers of not doing so are already large and will grow with time.

For this reason, Transpower has engaged Castalia to develop a methodology for quantifying competition benefits from transmission investment, which is presented in this report. Specifically, this report:

- Presents the rationale for reinvestigating the competition benefits of transmission investment (Section 2)
- Outlines our general approach and sets out a step-by-step methodology for estimating market power costs and competition benefits (Section 3)
- Outlines proposed next steps for implementation (Section 4).

Further, Appendix A Presents the results of a test run of Step 2 of our methodology that demonstrates that wealth transfers are already large.

2 Rationale for reinvestigating the competition benefits of transmission investment

Reduced competition due to transmission constraints in electricity markets can impose significant costs on consumers, contribute to regional disparities, and distort economic activity. These effects are likely to worsen as variable renewable energy (VRE) becomes a larger part of the generation mix. For this reason, this paper argues for reconsidering including competition benefits of transmission investment when assessing merits of a transmission investment.

- Section 2.1 briefly recaps how transmission limits prevent effective competition from reaching certain nodes, allowing some generators to become net pivotal and price well above short-run marginal cost
- Section 2.2 argues that if prices rise due to constrained competition, the resulting transfers from consumers to producers can create welfare concerns, and that reducing these transfers falls within the Electricity Authority's mandate to promote competition
- Section 2.3 shows that earlier assessments may have underestimated the scale of these effects
- Section 2.4 discusses how sustained higher prices could, over time, reduce electricity demand, have negative impacts on the economy beyond electricity markets, and increase the likelihood of reactive government intervention
- Section 2.5 concludes that as the generation mix shifts toward VRE, these issues are likely to become more frequent, strengthening the case for reassessing how competition benefits are treated in transmission planning.

In short, this paper argues that including the competition benefits of transmission when considering transmission investments is inherently within the EA's remit. Further, while it is a departure from market orthodoxy, the existing impacts of constrained competition due to transmission constraints on consumer prices are already putting pressure on the Government to act, and the energy transition will increase those impacts and pressure. Thus, we believe it is prudent for the EA to revisit including the competition benefits of transmission investment in its regulatory decisions because it is an efficient solution that is likely less distortionary than political interventions that will result from growing impacts on consumer prices.

2.1 Transmission constraints can allow market participants to exercise market power in constrained nodes

Unlike most commodities, electricity must be produced and consumed instantaneously and is traded within a network that has physical constraints. Nodal pricing captures these spatial realities but also enables localised pricing anomalies when constraints prevent generation competition from reaching certain nodes.

In a perfectly competitive electricity market of the type operating in New Zealand, wholesale power prices at a given node, in a given pricing period should reflect the short-run marginal cost (SRMC) of the marginal generator for the relevant node and period. However, when transmission constraints limit the number of effective competitors at a node, generators can obtain temporary price setting ability—often referred to as being **net-pivotal**.[1]

Instances of generators becoming net-pivotal are episodic, but material. They are most likely to arise during periods of:

- high load
- limited dispatchable generation
- outages or de-ratings
- structural transmission bottlenecks.

In time periods when a generator becomes net pivotal, the system operator must accept some portion of that generator's offer to meet demand at the node (because there is no other alternative to satisfy demand at the node, other than shedding load). Knowing this, the generator can profitably submit part of its offer stack at prices well above SRMC, secure in the knowledge that some, or all, of its capacity will be dispatched. This is a textbook case of market power: the ability to profitably raise price above marginal cost without losing market share.

Generators can create significant wealth transfers by marking up a small percentage of their offer stack when net-pivotal

Generators can submit most of their capacity at short-run marginal cost, confident it will be dispatched, but withhold a small portion—typically the final block most likely to set the market price—and offer it at very high prices, sometimes near the administratively defined Value of Lost Load (VoLL).[2] If that final block is dispatched, it sets the market price for all power traded at that node in the relevant time period.

As argued in *Power System Economics*, allowing prices to rise toward VoLL during scarcity periods is consistent with efficiency and necessary for reliability.[3] It sends a signal to consumers and generators about the value of capacity during peak events and provides revenue to support long-term investment.

However, this principle assumes that scarcity is genuine, not manufactured by constrained competition. When a generator becomes net pivotal due to transmission limits, its ability to submit near-VoLL offers does not reflect scarcity of generation supply in the grid, but rather a lack of competitive pressure on that node due to constraints that prevent shifting competing supply to that node from other parts of the grid.

This strategic behaviour, while consistent with market design, can lead to additional costs being imposed on consumers, creating a wealth transfer from consumers to generators. As the number of competitors falls or the residual supply margin tightens, the incentive and ability to bid above cost can increase. The cumulative impact of these periods can affect average power prices and consumer welfare.

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1 The Market Development Advisory Group defines a net pivotal position as "a supplier is a party that is required to generate to avoid unserved load and whose generation is greater than its own retail and hedge sales in the relevant area" Source: https://www.ea.govt.nz/documents/2456/25343Trading-conduct-review-pivotal-workshop-briefing.pptx

2 VoLL represents the economic value consumers place on avoiding involuntary outages

3 Stoft, Steven. *Power System Economics: Designing Markets for Electricity*. IEEE Press; Wiley-Interscience, 2002.

Transmission investment can help alleviate these constraints by increasing the number of effective competitors at constrained nodes.

By easing grid bottlenecks, it becomes harder for any single generator to control prices and more likely that offers reflect true generation costs. As a result, fewer opportunities arise for generators to extract high prices, which can reduce the scale and frequency of wealth transfers from consumers to producers, delivering a direct benefit to consumers.

2.2 Considering the effect of wealth transfers on consumer prices is within the Electricity Authority's mandate

Transpower has in the past sought to encourage the Electricity Authority (EA) and market participants to place greater weight on competition benefits when evaluating transmission investments. Progress has been limited, in part because of the challenges involved in quantifying these benefits. Further, stakeholders could maintain that wealth transfers arising from transmission constraints should fall outside the EA's consideration. This section argues that the reduction of wealth transfers is a benefit that the EA should recognise.

The wealth transfers from consumers to producers arise due to a lack of competition

When transmission limits reduce the number of effective competitors, some generators can raise prices without higher underlying costs. In these situations, prices reflect market power rather than the true cost of generation. In a counterfactual with more available supply, no generator would become net pivotal, and electricity would be supplied closer to short-run marginal cost.

Without effective competition, the upward pressure on electricity prices persists, and consumers bear the cost

Constrained competition allows producers to increase prices, and if they do, consumers must bear the additional cost. Transmission investment helps keep such price increases in check by limiting generators' ability to offer prices well above short-run marginal cost.

Recognising these transfers as competition benefits is consistent with the Authority's statutory and policy mandate to promote competition for the benefit of consumers

The Electricity Industry Act 2010 makes competition a central objective of the Electricity Authority. The Act states: "The main objective of the Authority is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers."[4] Reducing the opportunity for generators to become net pivotal is one way to support that mandate, because the net pivotal position occurs when there is limited competition.

Further, in October 2024, the Government issued a policy statement to the Electricity Authority emphasising that it "expects the electricity system to deliver reliable electricity at the **lowest possible cost to consumers**. It should serve the interests of all electricity consumers, including through the provision of sufficient electricity infrastructure to ensure security of supply and **avoid excessive prices**."[5] Not accounting for competition benefits of transmission investments could lead to investment decisions that overlook cost-effective ways

4 https://www.legislation.govt.nz/act/public/2010/0116/latest/DLM2634339.html

5 https://www.beehive.govt.nz/sites/default/files/2024-10/Government%20Policy%20Statement%20on%20Electricity%20-%20October%202024.pdf

to limit price increases, undermining the system's ability to deliver electricity at the lowest possible cost.

Taken together, these arguments show that recognising reductions in wealth transfers resulting from competition benefits of transmission investment is not only consistent with the Authority's mandate and government policy but also essential to ensuring transmission investment decisions properly reflect the long-term interests of consumers.[6]

2.3 The scale of wealth transfers is likely much larger than previously assumed

The wealth transfers from consumers to producers caused by constrained competition may already be larger than earlier assessments suggested, and they are set to increase. For example, a 2008 report by McLennan Magasnik Associates (MMA) assessed competition benefits from upgrading the HVDC link using game-theoretic modelling. It found modest benefits under most scenarios, with higher benefits ($42 million NPV) only in the high-renewables case. MMA focused on productive efficiency, that is, how increased transmission could reduce total generation costs by limiting strategic withholding. It did not examine consumer price impacts or model prices at specific constrained nodes.

MMA's report estimated competition benefits using system-wide annual average prices. This approach underestimates the impacts on customer prices. Our proposed approach, which focuses on actual bidding behaviour during specific periods when transmission constraints limit regional competition, demonstrates that wealth transfers and their impact on consumer welfare is much larger. The box below shows how focusing on real-world uplift prices, not theoretical annual averages, reveals the potential scale of consumer impact from transmission constraints.

Box 2.1: Illustrative Competition Benefits from an HVDC Upgrade

The MMA report found an annual average uplift price of $10–15/MWh across the grid for 2005 and estimated the competition benefits of the HVDC upgrade at a maximum of $42 million NPV, or approximately $4.2 million per annum.
In contrast, our approach focuses on specific times and locations when transmission constraints limit regional competition, resulting in uplift prices of up to $5,000/MWh. Unsurprisingly, this yields vastly different estimates for the annual value of consumer benefits from upgrades such as the HVDC link.

Illustrative straw-man scenario: HVDC upgrade in the mid-2030s

- Peak North Island demand grows to about 5,000 MW by the 2030s

[6] We do not suggest that transmission investment is the only solution, or necessarily the optimal one. Our concern is that if competition benefits are excluded from decision-making, the result may be choices that advantage certain producers while leaving consumers worse off, with potential harm to the wider economy.

- Most of the new generation is variable renewable energy (VRE), consistent with EA's Generation Investment Pipeline.[7] Gas has a constrained role due to falling supply.[8]
- Transmission constraints cause one generator to become net pivotal during peak periods

Year 1: Net pivotal status for 0.1% of the year (about 8 hours)
Generator bids $5,000/MWh* above SRMC
Cost = 8 hours × 5,000 MW × $5,000/MWh = $200 million p.a.

Year 2: Load grows by 1%, net pivotal status rises to 1% of the year (about 80 hours)
Generator bids $5,000/MWh above SRMC
Cost = 80 hours × 5,050 MW × $5,000/MWh ≈ $2 billion p.a.
Without investment, these uplift costs would continue to grow. Upgrading the HVDC link could avoid these excessive prices, delivering significantly higher consumer benefits than those estimated using the MMA methodology.

Key point: The above is not a forecast but serves to illustrate the scale of difference that can arise from our more targeted approach to identifying uplift prices compared to historical average-based methods.

*Appendix A demonstrates that, during periods when they are net-pivotal, generators have been offering very high prices for a portion of their bid-stack.

There is strong evidence that generator-retailers (gentailers) are using their net-pivotal position to maximize their profits. A study by Stephen Poletti from the University of Auckland Economics Department suggests that gentailers are already earning an excessive rate due to the exercise of market power (not necessarily all from transmission constraints) to the tune of hundreds of millions of dollars. [9]

Further, the impacts of transmission constraints are likely to fall disproportionately on specific nodes, having outsized impacts on regional economies. Our analysis focuses on those nodes. Meanwhile, previous analysis done by MMA looked at the North and South Islands as a whole, ignoring node-level transmission benefits risks ignoring regional impacts.

2.4 Wealth transfers have broader economic effects that will invite political intervention

Transmission constraints that lead to wealth transfers from consumers to producers can have wider economic implications. This section examines how sustained higher electricity prices may reduce demand over time, affect regional industries, and increase the likelihood of reactive government intervention. These risks strengthen the case for recognising competition benefits in transmission planning.

7 Generation investment pipeline | Electricity Authority

8 MMA assumed gas would continue to play a balancing role in the generation mix. This is no longer the case. As highlighted in a recent RNZ report, the Ministry for Business, Innovation, and Employment has warned that gas supply is falling faster than previously expected. This raises serious concerns about the reliability of gas as a transition fuel and its ability to support stable supply of electricity.

9 https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4045133

Sustained higher consumer prices will reduce demand over time

If the increasing share of intermittent generation drives prices significantly higher either nationally or in particular regions, it could have broader economic impacts. In the short run, electricity demand is inelastic, but over the longer term, sustained higher prices can impact demand for electricity and affect the wider economy.

Higher prices can push out firms that have higher electricity needs, which could have serious consequences for regions that are reliant on particular industries. For example, in 2024, Winstone Pulp shut down two North Island mills, resulting in hundreds of job losses. The company cited high electricity prices as the reason for shutting down. The news attracted much political and media attention.[10]

At this point, we do not know which regions or which industries could be impacted. However, if we proceed with this analysis, then we might be able to identify the risks. The analysis would allow decision-makers to make better decisions about the future investment choices that consider both the national and regional impact.

Sustained higher prices can invite inefficient government intervention

Higher prices are likely to trigger strong knee-jerk political/regulatory intervention that would further distort market outcomes. High electricity prices have already been inviting more regulation. Just in recent months, pressure has been building on the government for more intensive regulation in the electricity market. For example:

- Consumer NZ has argued that the electricity market is failing consumers[11]
- The Electricity Authority has announced plans to boost competition between gentailers to address concerns about high electricity prices and market power.[12]

Similarly, in Australia the Australian Energy Market Commission's review highlights the pressure to increase regulation in response to rising consumer bills and structural market issue.[13]

These interventions are likely to create unintended consequences that will have a much greater distortionary effect on the market than considering competition benefits of transmission investment. For example, Richard Meade, a professor at the Centre for Applied Energy Economics and Policy Research at Griffith University, argued that the recent interventions in the New Zealand electricity market might have unintended consequences like reduced investment or even higher long-term prices.[14]

In short, our view is that it is likely more efficient to examine considering competition benefits of transmission investments, even if it is a diversion from pure market theory, than to wait for the impact on power consumers to become so great that it moves the Government to take reactionary measures that will diverge even further from market design.

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[10] https://www.1news.co.nz/2024/09/10/hundreds-of-jobs-to-go-as-winstone-pulp-confirms-mill-closures/

[11] Why is the electricity market failing people? - Consumer NZ

[12] https://www.interest.co.nz/economy/134787/level-playing-field-electricity-authority-announces-plans-boost-competition-between

[13] https://www.aemc.gov.au/market-reviews-advice/pricing-review-electricity-pricing-consumer-driven-future

[14] https://theconversation.com/an-attempt-to-lower-nz-electricity-prices-could-end-up-doing-the-opposite-heres-why-263519

2.5 Wealth transfers will increase in coming years due to growing use of intermittent generation, making them harder to ignore

Structural changes in the electricity sector are likely to increase both the frequency and magnitude of wealth transfers arising from constrained competition. This section outlines how a growing share of intermittent generation raises the likelihood of high-price periods and leads to even higher consumer prices. These developments support the need to consider competition benefits in investment decisions.

EA's generation development pipeline shows that nearly 99% of new load growth will be met by resources that cannot operate flexibly for extended time periods.

Analysis of the Electricity Authority's generation development pipeline shows that while 83% of proposed new generation by capacity is intermittent, most of the remaining 17% is either batteries (15%) or inflexible geothermal (1%), leaving only about 1% of total planned capacity that is both flexible and capable of sustained flexible operation.

The high share of VRE increases the risk of high-cost periods, which may lift average prices over time

As more VRE—including consumer energy resources—enters the grid, dispatchable generators can become net pivotal sooner and more often. This is because increased VRE decreases the incentives for dispatchable generators to enter the market.

This will result in more periods when demand is high and supply is low because VRE is not producing, and there are fewer available dispatchable generators in a particular part of the network. As a result, more generators will become net pivotal and could increase their prices more often. This means that periods of near VoLL pricing will also increase. Thus, while VRE won't necessarily push up median costs due to falling cost of VRE and storage, it will create periods of very high prices, which can in turn raise average prices over time.

In effect, this increases the competition benefits that can result from transmission investment—potentially significantly—and brings those benefits forward. As such, we believe it is timely to reconsider including the competition benefit of transmission investment due to a material change in the structure of the market.

3 Detailed methodology

This section explains the methodology we propose to estimate competition benefits from relieving transmission constraints. This section first defines Market Power Cost (MPC) and outlines our conceptual approach for deriving MPC. It then details our six-step methodology for calculating MPC and subjecting our calculations to sensitivity analysis to ensure that they are robust.

3.1 Definition of Market Power Cost

We define **Market Power Cost (MPC)** as the additional cost imposed on consumers when generators offer above their SRMC and are dispatched due to being in a net pivotal position at the relevant node. It is the difference between:

- the price that would have cleared the market at the node under competitive conditions (that is, assuming all generators offer at SRMC); and

- the actual market price that clears when one or more generators bid strategically, because they are (or expect to be) net pivotal.

Formulaically:

MPC = [P (strategic) – P (competitive)] × Energy

- P (competitive) is the price resulting from SRMC offers
- P (strategic) is the price resulting from strategic bidding under constrained conditions
- Energy is the amount of locally demanded energy (in megawatt hours) traded at P(strategic).

This cost can reflect excess payments made by consumers during periods when market outcomes diverge from competitive levels due to grid constraints.

3.2 Approach

Our approach is to use a virtual Scheduling Pricing and Dispatch (vSPD) or equivalent model with simple modifications to create a tool that, for any proposed investment, uses four carefully designed runs of a vSPD or equivalent model to create a robust estimate of the proposed investment's competition benefits. The table below summarises the modelling scenario structure that we plan to use to estimate the competition benefits in an area of the grid where a transmission investment is proposed to be built.

Figure 3.1: Modelling scenario structure

	Perfect Competition	Strategic Behaviour
Constrained grid (1A/1B) *in the future*	**1A.** *SRMC bids on a future grid where the potential investment has **not** gone ahead.* **Shows:** Pre-investment hypothetical price pattern on relevant nodes with assumed perfect competition.	**1B.** *SRMC offers, but mark-ups are triggered when pivotal on a future grid where potential investment has **not** gone ahead* **Shows:** Pre-investment expected actual price pattern on relevant nodes given imperfect competition.
With the proposed investment *in the future* (2A/2B)	**2A.** *SRMC bids on a future grid where the potential investment **has been made**.* **Shows:** Post-investment hypothetical price pattern on relevant nodes with assumed perfect competition.	**2B.** *Mark-ups are triggered on a future grid where potential investments have **been made**.* **Shows:** Post-investment expected actual price pattern on relevant nodes, incorporating any improvement in competition due to the investment.

With these four outputs, we create two simple yardsticks:

- An estimate of the foreseeable future cost of market power in the relevant area of the grid **without** the proposed investment. We measure this as the difference in price outcomes between scenario 1B and scenario 1A. Let's call this Market Power Cost 1 or MPC1. MPC1 = 1B – 1A

- An estimate of the foreseeable future market power costs in the relevant area of the grid **with** the proposed new investment in place. We measure this as the difference in price outcomes between scenario 2B and scenario 2A. Let's call this MPC2. MPC2 = 2B – 2A

We can then estimate the net competition impact of the proposed investment by taking the difference between the two MPCs. The project under consideration has a net competition benefit if MPC2 is lower than MPC1 under the investment scenario. That is, if the following calculation gives a positive number: Competition benefit = (1B – 1A) – (2B – 2A).

In short, we provide a straightforward, yet rigorous way to see how much a new transmission investment could reduce market power costs for New Zealand power consumers by pairing a perfect-competition run with a rule-based strategic run on the area of the grid that would be impacted by the new transmission investment with and without the proposed investment.

Why this approach works:

- **Uses the same solver that sets real-world prices.** The model used for the analysis is a replica of Transpower's live SPD engine, so every run respects all nodal constraints, losses, reserves, and pricing rules already accepted by regulators.
- **No black-box model.** We use existing modelling capability and techniques already embedded within Transpower. We simply feed two alternative bid stacks into the existing models to be run as scenarios. Transpower staff stay in full control of data, code, and daily operation.
- **Forward-looking by design**. Because the workflow inputs a full demand and generation forecast, it can test 2030 or 2040 scenarios just as easily as replaying history.
- **Transparent strategic overlay.** The bid-adjustment rule we will use for scenarios 1B and 2B will be a short script. It will check each half-hour's Residual Supply Index and, if a portfolio is pivotal, apply a calibrated mark-up or MW withholding. Parameters will be calibrated so the model reproduces the size of price-cost gaps observed in recent high-price episodes, then frozen for future scenarios, with a process for periodic updates.
- **Clear, relatable outputs.** For every node and trading period, the method can produce the incremental costs borne by consumers when market power is possible and exercised, and how much those costs reduce (or increase) when the new investment is added.
- **Sensitivity analysis.** This will address concerns that the specific methodology for calculating MPC is unduly influencing the outcome, allowing for a more robust and accepted approach.

3.3 Methodology

Figure 3.2 summarises our proposed six-step methodology to develop the four scenarios described above.

Figure 3.2: Summary of the process

Step 1	Determine areas with *current* grid constraints
Step 2	Identify current strategic bidding patterns in constrained areas of the grid and quantify the incremental costs to consumers relative to hypothetical SRMC bidding to calculate MPC lift
Step 3	Identify areas of future grid constraints and apply MPC uplift measure from step 2 to those areas to quantify future MPC **(MPC1)**
Step 4	Run SRMC and MPC uplift scenarios with proposed transmission investment under evaluation at a determined point in the future **(MPC2)**
Step 5	Determine the net competition impact of grid investment. **Competition impact = MPC1 – MPC2**
Step 6	Conduct a sensitivity analysis using a range of assumptions for MPC lift

Steps 1 and 2 (Sections 3.3.1 and 3.3.2) identify where current constraints enable market power and analyse strategic bidding patterns to estimate the average associated cost to consumers. Step 3 (Section 3.3.3) projects where transmission constraints may create market power in the future and calculates how strategic bidding patterns will create MPC in each affected area of the grid before any transmission investments are made (MPC1). Step 4 (Section 3.3.4) models how the MPC for each area changes if proposed grid investments proceed (MPC2). Step 5 (Section 3.3.5) calculates the net competition benefit as the reduction in MPC resulting from transmission investment. Step 6 undertakes sensitivity analysis to see how the results change with a different set of scenarios and assumptions (Section 3.3.6)

3.3.1 Step 1: Determine areas with current grid constraints

In this step, we use the current grid and historical prices to determine where pivotal generators have raised prices in localised areas above the rest of the grid. We start by identifying when and where this has occurred using final pricing runs, including prices and constraints. We then analyse generator offers from these periods and locations to determine which offer set the localised high price, and whether the generator had uncleared offers above the price-setting offer.

Step 1.1: Identifying periods and locations

In this step, we identify times and locations on the current grid where a constraint has caused local prices to rise materially above the rest of the grid.

To identify these periods, we scan final prices to flag instances where any node or area is materially above the average for the rest of the grid in that period. We use two potential indicators:

- The ratio of standard deviation of prices at all nodes for that period to the average price of all nodes for that period exceeds a set threshold
- The ratio of the maximum price of any node to the average price of all nodes exceeds a set threshold.

Either approach can be implemented using a basic R or Python script. Ideally, the dataset would span about 20 years to cover a range of conditions. This will allow the analysis to cover a range of hydrological conditions (for example, wet, average, and dry years).

Once we identify the periods when prices vary widely across the grid, we then identify the areas where prices are materially above the rest of the grid in terms of $/MWh. The materiality test is important, as local price differences can arise without the exercise of market power. For example, if the short-run marginal cost of a local generator is higher than that of the marginal generator elsewhere. We would consult closely with Transpower on what the threshold should be for materiality; however, our initial analysis suggests that when Market Power is exercised due to transmission constraints there is a considerable price difference such that the choice of materiality threshold likely will not make much difference in identifying nodes unless the materiality threshold were set very high.

Step 1.2: Pull out the offers stack for relevant generators

Having identified the periods and locations where high prices occurred, we then identify which generator offer caused the high price, the size of the offer band, and any uncleared offers above that band. This provides a useful cross-check to assess whether the price-setting offer potentially reflects the exercise of market power. We can compare it with the generator's other offers to see if there is a price jump. This price jump test could also be set as an adjustable parameter.

The size of this high-price offer band, including the uncleared portion, helps determine how often similar high prices may occur in the future. For example, if the band is large but only rarely cleared now, future load growth in the area may result in it being cleared more frequently. This could also lead to the currently uncleared portion being dispatched, resulting in even higher prices.

3.3.2 Step 2: Quantify MPC uplift resulting from strategic bidding

Rather than analyse the specific grid and generation configuration for each case, we will focus on developing a general statistical measure of MPC uplift in constrained areas of the grid. We will focus on how much offer prices exceed the rest of the market, rather than absolute price levels. The aim is not to assess overall market competitiveness, but to examine price increases in constrained areas relative to the rest of the market. We propose two potential methods for quantifying MPC uplift depending on Transpower's data availability.

Preferred Methodology – Use Binding Constraint List to Filter Periods of Interest (If Data Available)

If Transpower **has** access to a list of binding constraints per pricing run, then:

- Identify all runs during which a transmission line hits its limit.
- If the pricing dual of the constraint is available, sort these to select the ones with the highest value above a threshold (for example, $100/MW).

- If not, filter these cases based on the price volatility ratio (STD (price)/Ave (price)).[15]
- For this subset of pricing cases, find:
  - The affected localized area (filter nodes based on the extent to which prices are above average to find the affected region).
  - For generators associated with the nodes in the affected localized area, find the highest cleared offer.
- For generators outside the affected localized area, find the highest cleared offer.
- The MPC uplift is the difference between these two sets of offers.

It would also be helpful to obtain the uncleared offers for the generator identified above as having the highest cleared offer in the affected localised area. The purpose of this is to understand if the MPC uplift would further increase should load growth continue on a constrained node without additional generation investment (since this may result in offers clearing higher up the bid stack in the future). Box 3.1 illustrates how local load growth can increase MPC in constrained areas.

[15] Note as agreed with Transpower, we will only look at energy prices at this point.

Box 3.1: Example of how local load growth can increase MPC in constrained areas.

Setting

The grid has three nodes—A, B, and C. A single line into Node A is constrained, making Generator X at that node net pivotal. During one trading period:

- Prices at B and C clear close to $100/MWh (the short-run marginal cost, SRMC).
- Generator X bids a 15 MW tranche at $300/MWh and a second 5 MW tranche at $600/MWh.
- Total local demand at Node A is 100 MW, of which 15 MW must be met by Generator X due to the constraint. The remaining 85 MW is met by supply transmitted from other nodes.

Today's outcome

- Only the $300/MWh tranche clears.
- Average market price (nodes B + C) = $100/MWh.
- Price uplift at Node A = $300 − $100 = $200/MWh.
- MPC at A = 100 MWh × $200 = $20,000.

Why the size of the "high-price band" matters

The second 5 MW tranche at $600/MWh remains uncleared today, but it still matters because if local demand grows to 25 MW, the $600 tranche will set the price.

Future scenario (110 MW load at A)

- Both tranches clear; marginal price = $600/MWh.
- Price uplift = $600 − $100 = $500/MWh.

Market-power cost = 110 MWh × $500 = $55,000

Implication for investment decisions

This example shows why we focus on the difference between Node A's price and the broader market, not the absolute price level. The larger (and less frequently cleared) the high-price band, the greater the potential future cost to consumers if load grows. Also, this example was for a single trading period. As the load grows, the frequency of periods with high pricing also grows. So, as both the impact per period and the number of affected periods grows the overall impact can grow very quickly.

Fallback Methodology – Based on Data Available from EMI

If Transpower does **not** have access to binding constraint data, then:

- Identify locations and periods where high localised prices occurred.
  - Sort ALL pricing cases based on the price volatility ratio (being STD (price)/Ave (price).
    - Identify periods where price volatility was above a threshold. These are the periods where a binding transmission constraint likely caused price separation.
    - For each identified period, determine the affected localised area by ranking nodal prices from highest to lowest and identifying where there is a material break between adjacent prices. A large price gap indicates that the area above the break likely experienced localised price separation due to a constraint.
  - Calculate the average price for nodes in the affected localised area
  - Calculate the average price for nodes outside the affected area
  - Calculate the MPC uplift as the difference between these prices.

- Find the generator offers (prices and quantities) causing the high localised prices:
  - For generators inside the affected area, identify the offers that set the price—that is, offers with prices equal to the final price at that node
  - For these generators, record the quantity in megawatts of both the price-setting offer and any uncleared offers, including both quantities and prices
  - Determine what percentage of the available generator capacity this offer quantity represents
  - Divide these net pivotal, price-setting offers into three tranches as price–quantity pairs, expressing quantity as a percentage of available generator capacity
  - Take a large sample of such situations (for example, 20 years of data) and calculate the average of each price–quantity tranche
  - Use these three price–quantity tranches as stylised market power offers to be applied in step 3.

Appendix A provides the results of a trial run of this approach.

3.3.3 Step 3: Identify areas with future grid constraints and calculate MPC in those areas without transmission investment (MPC1)

In this step, we use insights from historical market power costs to assess how similar conditions might affect future market power costs. For example, if a generator was net pivotal in the past and drove market power costs, will this situation worsen with local load growth, or improve due to new generation in the area?

We approach this by identifying where net pivotal situations could arise, then applying the MPC uplift (derived from the historical analysis) to dispatchable resources, including generators or Battery Energy Storage Systems (BESSs) in those areas.

Step 3.1 – Identify from the generation development scenarios grid areas where generators may become net pivotal

Consider how the grid will evolve using Transpower's generation development scenarios, considering:

- Local load growth vs. local generation investment
- Any increases in intermittent generation and resulting volatility of supply
- Changes in local demand shape or BESS uptake.

Based on these scenarios, we will determine areas where generators may become net pivotal at a foreseeable point in the future. Transpower's grid investment planning process is likely to have already identified many of these areas as candidates for future investment. However, this analysis may add to that knowledge by highlighting additional areas where generators may become net pivotal.

Step 3.2 – Apply the MPC uplift (above the next cleared offer) to SRMC offers

For each area identified as potentially creating a net pivotal position for a generator, we will identify dispatchable generators (or other dispatchable resources, e.g., BESS) located within that region. These generators are capable of exercising market power under constrained conditions.

We will adjust their SRMC offers by adding three tranches of uplifted offer prices. Each tranche specifies a price above SRMC and a quantity, with the quantity expressed as a percentage of the generator's available capacity. The table below shows an example of how a 100 MW generator's offer stack would be adjusted using three market power price–quantity pairs, along with the corresponding uplift above SRMC.

Table 3.1: Example Application of Market Power Price–Quantity Tranches to SRMC Offers

Tranche	SRMC Price ($/MWh)/2	Uplifted Price ($/MWh)/2*	Capacity % for MPC (100 MW)	MPC Offer Capacity in MW	MPC (Uplifted Price – SRMC price)
1	50	300	10%	10 MW	$300 - $50 = $250
2	50	1,050	7%	7 MW	$1050 - $50 = $1000
3	50	5,050	3%	3 MW	$5,050 - $50 = $5,000

Note: This example is for an offer for a single trading period, but such offer structures would be applied to all periods under consideration.

**All MWh prices divided by two to reflect settlement based on half-hour trading periods*

Step 3.3 – Calculate MPC1 using these uplifted offers

To estimate the MPC1, we apply the uplifted offers from Step 3.2 to the areas we identified in Step 3.1. For each period where local prices exceed the SRMC case, we calculate MPC1 by multiplying the price difference by the local load. We repeat this exercise for every trading period when the constraint binds, and then we sum the results. The table below provides an illustrative example of this calculation for a selected trading period.[16]

Table 3.2: Example Calculation of total Market Power Cost

Tranche	SRMC Price ($/MWh)/2	Uplifted Price ($/MWh)/2	MPC per unit ($/MWh)/2*	Local Load (MW)	Total Market Power Cost ($)
1	50	300	250	10	$2,500
2	50	1,050	1,000	7	$7,000
3	50	5,050	5,000	3	$15,000

**All MWh prices divided by two to reflect settlement based on half-hour trading periods*

3.3.4 Step 4: Calculate MPC in identified areas after transmission investment (MPC2)

In this step, we will estimate future market power costs with the proposed transmission investment in place (MPC2) by rerunning the relevant periods from Step 3 using the updated grid configuration as determined by Transpower's proposed grid investment. Transpower can size the required upgrade to an optimal level, so some congestion, and therefore some MPC, will likely remain.

[16] Some of the tools developed to identify historical market power costs may be useful for this step.

This may require covering a broader set of periods than those identified in Step 3, as the constraint could bind more frequently in the future, and the net pivotal offer strategy may include higher offers that did not clear in Step 3.

3.3.5 Step 5: Determine the competition benefit of grid investment in a future grid

The next step is to calculate the competition benefit of transmission investment in the grid focus area identified in Step 3 at a specified time in the future (as adjusted for in Step 2) by applying the formula MPC1 – MPC2 for the specific area affected by the transmission investment that will take place.

3.3.6 Step 6: Sensitivity analysis – Different offer strategies

Steps 1 to 5 lead to a single number for competition benefits based on MPC uplift offer strategies derived from historical data. However, we recognize that past offer strategies may not be an ideal indicator of future offer strategies and that, regardless, market participants are likely to take issue with any one defined approach to calculating MPC uplift. As such, we propose that a range of sensitivity studies should be undertaken, and the final competition benefits number should be the average over the range. Proposed sensitivities include:

- Market concentration
- Capping offer prices at $2000; and
- Reducing all uplift prices by 50%.

Table 3.3 below explains how we propose defining each factor.

Table 3.3: Sensitivity Analysis

Sensitivity Factor	Method
Market Concentration	From historical data, determine how offer prices vary with the number of marginal market participants within the region. Participants are marginal when they have un-dispatched offer quantities, and price separation from the rest of the grid occurs. Adjust the MPC uplift offer prices down by the value corresponding to one more marginal market participant - that is, one more participant with a dispatchable resource in the region.
Capped offer prices (capped at $2,000)	Cap all uplift offer prices at $2,000. The choice of $2,000 is slightly arbitrary, but it is a reasonable value partway between SRMC prices and the $5,000 offers we are seeing in historical offer data.
All uplift prices reduced by 50%	Simply reduce the MPC uplift offer prices by 50%. Again, the choice of 50% is slightly arbitrary, but it is useful to show how sensitive the calculated competition benefit value is to the offer strategy.

This approach is designed to help mitigate arguments about whether the MPC uplift is calculated correctly. At the same time, our intuition is that sensitivity analysis results may only show a small impact on the optimal timing of transmission investment. Adding a range of sensitivities to our approach, and only triggering changes in investment decisions due to MPC impacts when the result holds under all sensitivity case runs, would help address concerns about the potential imprecision of any single model run. In a situation where the result holds under all sensitivities, our approach can credibly deliver the key message that some unaddressed transmission constraints, more so than others, will create larger wealth transfers that will affect consumer prices.

4 Next steps

With the core methodology defined, the next step is to conduct a complete series of end-to-end tests. The results from these tests will then need to be analysed and refined. They can subsequently be used to develop a structured process to support decisions about transmission investment.

Incorporating this methodology in Transpower’s planning processes would result in clearer, more consumer-focused business cases for transmission investment. By systematically quantifying how grid upgrades can reduce the costs of market power, this approach has the potential to support more robust investment decisions that better align with consumers' long-term interests. Ultimately, it ensures that transmission planning not only addresses physical grid constraints but also promotes competition, helping to deliver electricity at the lowest possible cost and mitigating the broader economic impacts of constrained supply.

Appendix A: Results of a test run of Step 2

This section presents the results from our initial test run of step 2 of the proposed methodology. We outline the process and data sources used for the test (Section A.1), present the key findings related to strategic bidding (Section A.2), and discuss the implications these results have for the overall modelling framework (Section A.3).

A.1 Castalia Initial Test Run – Using EMI Data

Castalia completed an initial test run of Step 2, identifying market power costs using the fallback methodology and data from the EA's Electricity Market Interface (EMI).

A.1.1 Overview of Test Run

The steps below summarise how we used 18 months of EMI data to identify high-price periods, group nodes, extract generator offers, and derive price–quantity tranches for market power uplift.

- We loaded 18 months of final prices (from EMI monthly data files) into a database.
- We calculated a price separation metric for each period as the ratio of the standard deviation to the average price. If the metric exceeded a set threshold, we flagged that period and saved its metric in a new table.
- For each flagged period, we ranked nodal prices from highest to lowest and looked for a material break in the sequence—a large price gap between adjacent nodes. We used this break to separate nodes into a "HighPriceGroup" and an "Other" group.
- We then calculated the average price for each group: one for the HighPriceGroup and one for the Other group.
- We pulled the relevant offers from the Offer files for nodes in the HighPriceGroup with an associated generator.
- We identified the price-setting offer (the one equal to the final price at that node) and any uncleared offers (with prices above that node's price).
- We recorded the price and quantity for each of these offer tranches.
- We then compared each offer quantity to the generator's available capacity (the sum of all its offers for that period) and expressed the quantity as a percentage of capacity.
- We repeated this process across many high-price periods and groups in the test dataset.
- We aggregated the price-setting and uncleared offers, ranked them by price, and grouped them into three tranches (For this test we grouped tranches by price spread; however, through further analysis we will need to decide the best method for grouping the tranches—by price spread or quantity spread).
- From this aggregated data, we derived three market power uplift tranches—each defined by a price and quantity pair, with quantity expressed as a percentage of the generator's available capacity.

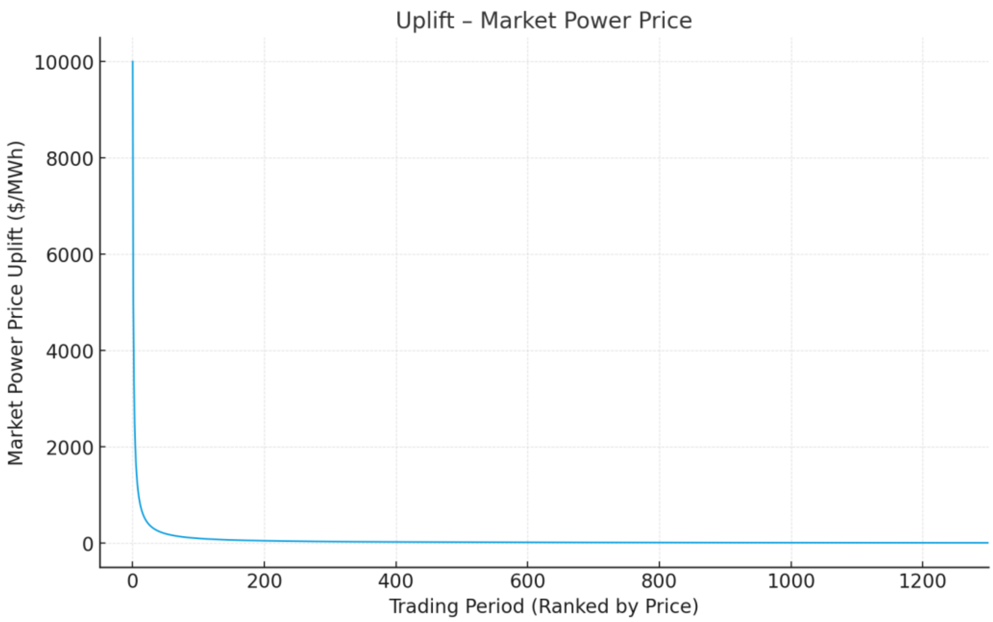
A.2 Test Run Results

This section summarises the test run results. The test run is not complete at the time of writing. A key finding so far is that most dispatchable generators include offers that rise toward a near-VoLL-priced component at the top of their stacks. When these generators become net pivotal in an area, these high prices are sometimes triggered by a binding transmission constraint. As a result, we localised price separation approaching near–VoLL levels (up to about $10,000/MWh) in some areas. We are still working to determine the details of the size and shape of these MPC offers.

A.2.1 Near VoLL Prices for Net Pivotal Generation

A key learning from the initial test of Step 2 is that some generators, when net pivotal, are cleared at prices near the VoLL. This behaviour is clearly visible in the price duration curve (PDC) in Figure A.1. The chart presents a PDC in which the x-axis shows trading periods ranked in descending order of Market Power Price, while the y-axis indicates the corresponding offer price in dollars per megawatt-hour.

Figure A.1: Price Duration Curve for Market Power Price[17]



The sharp incline at the left edge of the curve indicates a small number of periods with extremely high prices, above $10,000/MWh in some cases, followed by a long tail of lower prices. This skewed distribution is consistent with behaviour where generators facing little competition submit extremely high offers for some of their capacity, potentially reflecting strategic withholding or the exercise of market power.

[17] This graph is simplified for visual purposes.

A.2.2 VoLL Offers for Dispatchable Generation Common

Further examination of the offer stack from a range of generators for the periods in question shows that dispatchable generators commonly include a very high price (near to VoLL) in their offers.

These high-price periods coincide with generator offers at or near VoLL, as shown in Table A.1. For example, a participant offered 40 MW at $6,500/MWh for 24 consecutive trading periods on a single day. While this behaviour may align with market design, where high prices are allowed to signal scarcity, it reinforces the need to investigate whether new transmission investment can help reduce scarcity and, therefore, prices via increased competition.

Table A.1: Example High Price Offer Table[18]

Trading Date	Trading Period	Participant Code	Point Of Connection	Megawatts	$/MWh
30/09/2022	3	XXXX	ABC1234	10	6500
03/03/2023	1	XXXX	XYZ1234	40	6500
03/03/2023	2	XXXX	XYZ1234	40	6500
03/03/2023	3	XXXX	XYZ1234	40	6500
03/03/2023	4	XXXX	XYZ1234	40	6500
03/03/2023	5	XXXX	XYZ1234	40	6500
03/03/2023	6	XXXX	XYZ1234	40	6500
03/03/2023	7	XXXX	XYZ1234	40	6500
03/03/2023	8	XXXX	XYZ1234	40	6500
03/03/2023	9	XXXX	XYZ1234	40	6500
03/03/2023	10	XXXX	XYZ1234	40	6500

A.3 Implications for Competition Benefits Modelling

The results from the test run support a key theoretical assumption underlying our modelling framework: that dispatchable generators may rationally include a small tranche of near-VoLL offers when they anticipate becoming net pivotal. This behaviour aligns with standard economic theory, discussed in section 2, which explains that allowing prices to rise toward VoLL during genuine scarcity is efficient and necessary for investment signals.

When modelling future grids, we need to reflect how generators are likely to behave under constrained conditions. Including strategic behaviour in offer stacks ensures that Scenarios 1B and 2B capture realistic market power costs. This approach draws directly from observed patterns and economic theory, and it ensures the model identifies avoidable consumer costs that arise when transmission constraints reduce effective competition.

18 This table is anonymised for confidentiality purposes and is only indicative because it is a small sample.

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