Meridian submission

“Level Playing Field measures: Options Paper” proposing virtual disaggregation and non-discrimination obligations for Meridian, Genesis, Contact and Mercury

7 May 2025

This submission by Meridian Energy Limited (**Meridian**) responds to the Electricity Authority's (**Authority's**) "Level Playing Field measures: Options Paper" (**Options Paper**) proposing virtual disaggregation and non-discrimination obligations for Meridian, Genesis, Contact and Mercury.

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Table of contents

Executive Summary

This submission addresses the Electricity Authority's "Level Playing Field measures: Options Paper" which proposes the virtual disaggregation of and non-discrimination obligations for Meridian, Genesis, Contact, and Mercury.

Meridian supports an efficient, competitive and reliable electricity market. Competition in both the retail and wholesale markets helps drive efficient prices, high standards of customer service and the development of innovative products. We therefore support the Authority's goal of promoting greater competition in retail and wholesale markets to deliver long-term benefits to consumers. We will do our best to assist the Authority in the development and implementation of any proposed reforms to ensure they maximise benefits to consumers.

However, we believe the Authority needs to proceed with caution with respect to the proposed Level Playing Field measures. Meridian and our expert advisors – Carl Hansen (Capital Strategic Advisors) and NERA – have identified several potential risks with the Authority's proposal, including:

- higher electricity prices for households and businesses;
- net welfare losses for consumers; and
- dampened incentives to invest in new generation and flexibility.

If the Authority continues with its current proposal, we suggest several design details which we believe will need to be adopted to ensure these risks are minimised. These include:

- allowing generator-retailers to assume the notional internal hedge books they put in place have been built up over time;
- assessing the viability of a generator-retailer's internal business units over a commercially realistic timeframe; and
- providing for the non-discrimination obligations to apply only to actual physical participants in the New Zealand electricity market (as opposed to offshore speculators, traders or others).

We also believe, in deciding whether to progress this proposal, the Authority needs to consider the merits of vertical integration and how these have served – and continue to serve – the interests of New Zealand consumers. We have sought to highlight these merits in our submission.

Lastly, we would like to stress the importance of the Authority (as well as other regulators and policymakers) recognising and responding to the demise of New Zealand's gas sector in recent years. This has been the key driver of recent market constraints, including the events of Winter 2024, which set New Zealand on the current path of regulatory change. Preserving incentives for investment in new generation and flexible resources will also be critical to bring down wholesale prices and maintain security of supply through New Zealand's electricity sector transition.

Meridian appreciates the opportunity to comment on the Authority's proposal at this stage and we remain committed to working with the Authority to develop and implement changes that will benefit all electricity consumers.

1 Introduction

1.1 Meridian supports a competitive, dynamic and innovative electricity market

As indicated in our initial feedback to the Authority on its level playing field workstream, Meridian supports a retail market with a multitude of diverse parties competing intensely to win and retain consumers.[1] Such a market is most likely to drive efficient prices, high standards of customer service, the development of innovative products and, ultimately, value to consumers. As a major retailer, Meridian's experience is that the New Zealand electricity retail market is highly competitive and is delivering on these outcomes for kiwi households and businesses.

We also support a competitive wholesale market. We strongly agree with the Government Policy Statement on Electricity (**GPS**) that New Zealand's electricity system is best served by:

> *"…an efficient wholesale electricity market with many different wholesale buyers and sellers of electricity, managing their own risks, responding to competitive pressures and accurate price signals, continually looking for ways to serve their current and potential customers more effectively than their competitors".*[2]

In particular, a well-functioning wholesale market is critical for delivering investment. New Zealand needs 5 GW of additional renewable generation capacity each decade through to 2050 to deliver on our decarbonisation goals.[3] Meridian's own analysis indicates that the energy system also needs to add 200 MW of new flexible capacity each year for the next 25 years.[4] It is critical that both existing and new market participants have the confidence to invest to ensure that this additional capacity is delivered. Under current settings, both incumbents and new entrants are actively investigating, developing and commissioning new generation across the country. Care is needed not to dampen investment signals and create future security and affordability challenges, the costs of which would ultimately be borne by New Zealand consumers. We elaborate on our views on the functioning of both the retail and wholesale markets in Section 2.3.

1.2 The Authority's proposal must avoid adversely affecting investment or driving poor pricing outcomes for consumers

We understand the Authority is trying to achieve greater competition in wholesale and retail markets and, through this, deliver long-term benefits to consumers. We have commissioned analysis from two expert advisors: Carl Hansen (Capital Strategic Advisors or **CSA**) and NERA. Both have identified concerns with the Authority's proposal. In particular, they are concerned the proposal will:

(a) Drive increases in household electricity prices in the short term, generating a net welfare loss for consumers; and

(b) Dampen incentives to invest in new generation and/or flexibility.

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[1] Meridian response to request for feedback on level playing field measures, November 2024, link
[2] Government Policy Statement on Electricity, October 2024, link
[3] The Future Is Electric report, BCG, October 2022, link
[4] Flexible capacity might include batteries, new thermal (local or imported gas), new large scale demand response, biofuels (i.e., Bio-Rankine), new hydro storage etc.

The expert reports are attached as **Appendix D** and **Appendix E** and are referenced throughout this submission.

Meridian shares the concerns of our expert advisors. We consider there to be a risk of higher and more volatile retail prices as a result of the proposal, and for critical investment to be discouraged. We detail these concerns in Section 4.

1.3 We will do our best to make any intervention work for consumers

We acknowledge this is an initial proposal from the Authority.[5] We are grateful for the Authority's willingness to engage with us and other stakeholders on the proposal during the consultation period and we welcome the opportunity to provide feedback at this stage.

In Meridian's opinion, if the Authority intends to develop this proposal further, several changes are necessary to improve its workability and mitigate the risk of unintended consequences and costs to consumers. Meridian's suggestions are set out in Section 4.8.

We also consider that there are a number of alternative interventions or approaches which could help address the Authority's underlying concerns while avoiding the risks outlined above. Both Carl Hansen and NERA have proposed such alternatives. These are discussed in Section 5. We think these alternatives warrant careful consideration to ensure the path the Authority ultimately pursues delivers on the outcomes the Authority is seeking. We would be happy to engage with the Authority further on the development of these alternatives.

Ultimately, Meridian wants to see a well-functioning, efficient and competitive electricity market that is delivering for New Zealand consumers. That is best for Meridian, best for the sector, and best for New Zealand. We will continue to work with the Authority as it develops its proposals and will continue to provide our frank assessment of the likely outcomes of any interventions proposed. Once any intervention is finalised, we will work to implement any changes in a way that delivers the best outcomes for consumers.

2 Explanatory context

Before addressing directly the Authority's proposal, this section sets out some explanatory context that we believe is directly relevant. It discusses the reasons for the prevalence of vertical integration in the New Zealand electricity sector and describes the competition and investment that has occurred within the current market construct. It goes on to discuss the Authority's problem diagnosis in the wake of Winter 2024 and considers the relevance, if any, of the Authority's underlying assumption of an unlevel playing field to what transpired over Winter 2024. Finally, it reflects on lessons that might be drawn from regulatory measures pursued in the United Kingdom in recent years which were similarly intended to promote competition in the electricity retail market.

2.1 Benefits of vertical integration in the New Zealand electricity sector

The advantages of adopting a vertically integrated structure to manage volatility in wholesale electricity markets have been well canvassed in New Zealand and around the world.

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[5] We acknowledge in particular the Authority has indicated that the proposal has had less opportunity for input from industry given the Authority determined it was 'price sensitive' and has therefore largely developed the proposal in isolation.

Appendix B sets out conclusions from recent academic and regulatory considerations of this issue, including the Authority's own assessments. In short, there is a wealth of evidence – in New Zealand and globally – that vertical integration is an efficient business model that delivers significant consumer benefits while, in contrast, vertical separation would work to the detriment of consumers.

The benefits of vertical integration are also discussed extensively in our expert reports from Carl Hansen and NERA.[6]

2.2 Meridian's approach to portfolio management

Appendix C provides a description of how Meridian's approach to portfolio management has evolved and details some of the relevant considerations and trade-offs that we are continually required to make. In the context of the Authority's proposal, key points of note include:

(a) The balance Meridian has achieved as a vertically integrated business has not happened by accident: we have spent years efficiently managing and investing in our existing hydro and wind assets, creating new generation and new flexibility assets, securing a large pipeline of new generation and flexibility options, establishing and evolving a carefully considered hedge portfolio, and building up a large, diverse retail and customer base including a number of formalised demand-response agreements.

(b) The success or otherwise of our commercial decisions are only determined in the fullness of time, when market conditions reveal whether any particular decision was a good idea or not. That is the nature of the significant market and investment risk that Meridian and other participants face.

(c) Any party – including independent retailers or new entrant generators – could adopt a similar approach to Meridian to managing their wholesale market risk. Indeed, Lodestone Energy has recently taken such a step.[7] It just requires long-term commitment, investment, and the balancing of risk and reward to be at the centre of their decisions.

2.3 The current market structure has delivered significant investment and strong competition

New Zealand's wholesale market has gone through several supply and demand cycles since its inception in 1996. At various times, regulatory and market uncertainty have also impacted incentives to invest. Despite this, investment in the sector has been considerable. Over $10 billion has been invested in new generation in the last 15 years with much of this occurring during low or flat demand growth periods.

And this investment is continuing. As set out in Table 1 and Table 2 below, 3.1 TWh of new generation production has been delivered in the last 24 months (7.2% of current demand) and a further 2.2 TWh is under construction (5.1% of current demand).[8]

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[6] Refer, for example, Sections 2 and 3 of Carl Hansen's report and Section 3 of NERA's report.
[7] https://lodestoneenergy.co.nz/lodestone-becomes-an-energy-retailer/
[8] We note this doesn't include recently announced Meridian projects, such as Ruakākā Solar Farm (see link) and Mt Munro Wind Farm (see link).

Table 1: Energy projects delivered over the previous 24 months

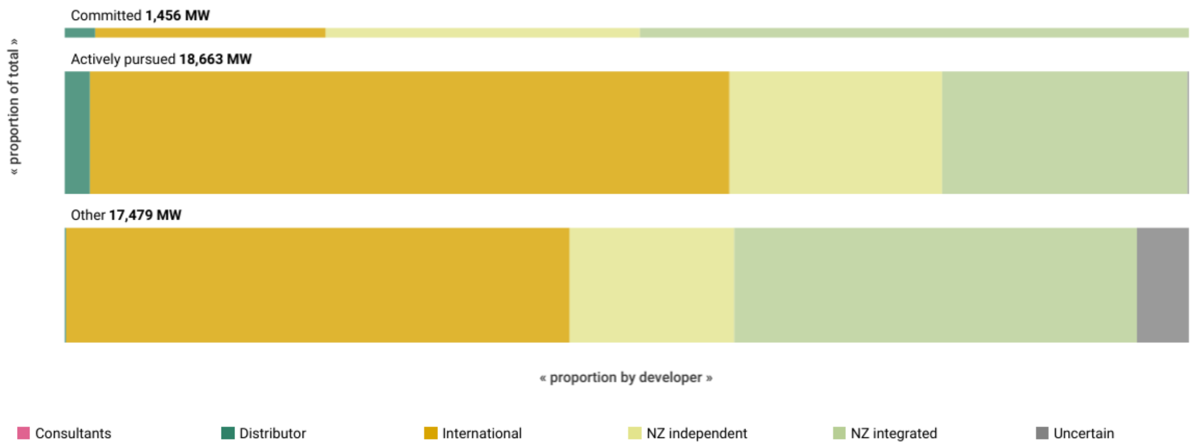
Project	Fuel	Developer	Commissioning Year	Annual Production (GWh)	% of 2023 Elec. Demand
Kaiwera Downs Stage 1	Wind	Mercury	2023	147	0.3%
Turitea	Wind	Mercury	2023	370	0.9%
Kohirā	Solar	Lodestone	2023	56	0.1%
Harapaki	Wind	Meridian	2024	542	1.2%
Tauhara	Geothermal	Contact Energy	2024	1450	3.3%
Rangitaiki	Solar	Lodestone	2024	54	0.1%
Te Herenga o Te Rā	Solar	Lodestone	2024	69	0.2%
Te Huka 3	Geothermal	Contact Energy	2025	430	1.0%
				3118	7.2%

Table 2: Energy projects under construction

Project	Fuel	Developer	Commissioning Year	Annual Production (GWh)	% of 2023 Elec. Demand
Lauriston	Solar	Genesis / FRV Aus.	2025	100	0.2%
Ngā Tamariki OEC5	Geothermal	Mercury	2025	395	0.9%
Topp2	Geothermal	Eastland Generation	2025	407	0.9%
Pāmu Rā ki Whitianga	Solar	Lodestone	2025	50	0.1%
Tauhei	Solar	Harmony Energy	2026	258	0.6%
Kaiwaikawe	Wind	Mercury	2026	221	0.5%
Kaiwera Downs Stage 2	Wind	Mercury	2026	525	1.2%
Kōwhai Park	Solar	Contact / Lightsource bp	2026	275	0.6%
				2231	5.1%

It is worth noting that around a third of generation under construction is being led by independent generators.[9] Carl Hansen similarly noted that the Authority's own investment pipeline shows that 51% of investments (measured in GW) committed for the period to December 2028 were driven by parties other than "NZ integrated", that is, other than generator-retailers.[10] For actively pursued projects, the generator-retailer share is only 23%.[11]

Figure 1: Committed, actively pursued and other generaton projects by developer type



Source: Electricity Authority

This evidence makes clear that not only is the electricity market delivering investment, but it is delivering investment by a diverse range of parties. The Authority seemed to previously acknowledge this in its May 2023 paper 'Promoting competition in the wholesale electricity market in the transition toward a renewables-based electricity system – Decision Paper' (**Decision Paper**) when it concluded:[12]

[9] Projects led by Eastland, Lodestone and Harmony total 715 GWh or 32% of total generation under construction.
[10] CSA, Section 2.1
[11] See https://public.tableau.com/app/profile/electricity.authority/viz/Investmentpipeline/Investmentpipeline
[12] Promoting competition in the wholesale electricity market in the transition toward a renewables-based electricity system – Decision Paper, Electricity Authority, May 2023, link

> *"The Authority considers that the current pipeline of investment (including a very significant portion from non-incumbents) is not consistent with anti-competitive behaviour holding back entry."*

It is unclear what has changed since 2023 such that the Authority now considers competition for investment in new generation to be a significant concern.

Meridian also considers the current settings have driven a highly competitive retail market. With around 40 retailers, New Zealand has almost double the number of electricity retailers per capita as Australia and over 20 times the electricity retailers per capita as the United Kingdom. Market concentration measures for New Zealand's electricity retail sector have declined consistently over the last 20 years.[13] The Ministry of Business, Innovation and Employment's (MBIE) electricity price data shows that household electricity costs have *declined* in real terms over the last ten years.[14] Taking an international perspective, New Zealand's domestic electricity prices rank seventh cheapest amongst IEA countries.[15] These are not indicators of a market with weak competitive forces.

Carl Hansen reaches a similar conclusion when considering the Authority's concerns about retail competition, noting that the real cost of the energy component of New Zealand household electricity prices has declined since 2020, "which does not support concerns that retail market competition is weak".[16]

Mr Hansen also observes that competition is delivering innovation in the retail market and that gentailers are often the drivers of that innovation:[17]

> *"It is a mistake to think that [Non-Integrated Retailers] are the primary drivers of innovation. Some will be, some of the time. But my understanding is that several gentailers have been revamping their retail divisions and introducing more technology to reach and retain customers during this period of allegedly stalled competition."*

2.4 The decline of the gas sector in New Zealand is central to the trends the Authority has observed, including wholesale prices in Winter 2024

Meridian notes that this proposal is the product of the 'Energy Competition Task Force' a collaboration between the Authority and the Commerce Commission involving both operating to some extent outside their traditional roles in an effort to increase competition in the energy sector. The Task Force was set up in September 2024 seemingly in response to the high prices observed in August 2024. While Meridian welcomes initiatives that increase competition, the events of August 2024 were not the result of any lack of competition in New Zealand's energy sector – they were the result of gas shortages. In our view, the more appropriate response to the events of Winter 2024 would have been to set up a Gas Sector Task Force.

We have observed an unfortunate regulatory pattern of overlooking problems in New Zealand's gas sector. In Meridian's view, the Authority, other regulators and officials have consistently not placed sufficient weight on the demise of the gas sector in New Zealand and more broadly have not placed sufficient weight on the importance of the gas sector in terms of its impact on the electricity market and on electricity prices.

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[13] https://www.emi.ea.govt.nz/Retail/Reports/R_HHI_C?_si=v|3
[14] Household sales-based electricity cost data, MBIE, December 2024, link
[15] https://www.gov.uk/government/statistical-data-sets/international-domestic-energy-prices
[16] CSA, Section 2.3
[17] CSA, Section 2.3

This has meant the Authority has not put in place measures that would ensure there was better disclosure of material information by the gas sector. In Meridian's view, this came to a head in August 2024 when the Authority, Meridian and the broader sector were caught by surprise by the lack of gas available for electricity generation.

Instead, the Authority has tried to explain the wholesale electricity price increases seen since the first Pohokura gas outages of 2018 in terms of supposed abuse or exercise of market power. While it is entirely right for a regulator to be alert to the possible presence of such issues, the Authority's persistence in looking for a 'market power' explanation despite the lack of evidence to support it and despite the more obvious explanations relating to gas issues, has meant, in our view, that the Authority has incorrectly diagnosed the problem.

For example, during the short period of high prices in August 2024, which it is now clear were the result of gas shortages, the Authority issued a press release which strongly implied that some kind of abuse of market power was taking place:[18]

> *"The Electricity Authority is not comfortable with the current high prices and we have moved swiftly to make sure the market is working properly. We are using all our powers to drill into why prices are so volatile and so high. We monitor market behaviour every week but this work goes even further. From next week we will be publishing new analysis to see what lies behind the current prices as the fuel shortage that we're experiencing can only explain so much. We will be testing to see if the prices are justifiable in the circumstances, which is why we are digging deeper and making the companies give us more information, so everyone can see exactly who is making what and to shine a light on the current situation."*

The new analysis referenced in that press release – which culminated in the publication of the Authority's Winter 2024 Review – ultimately revealed nothing untoward was going on and prices were found to be justifiable in the circumstances. In fact, it clearly identified gas shortages as the driver of high electricity prices:[19]

> *"…thermal generators did not have gas available to run at full capacity, and increased offer prices to prevent running out of thermal fuels. This fuel shortage resulted in a dramatic price increase."*

Quite appropriately the Authority Chair reportedly advised Parliament's Select Committee recently that "…the real issue last year was that gas supply declined faster than expected".[20]

In the Options Paper, the Authority references its May 2023 Decision Paper on the Review of Competition in the Wholesale Market and says that paper found that prices between January 2019 and mid 2021:[21]

> *"…to some extent…reflected underlying supply and demand conditions, but we noted that generators may have been exercising market power in the wholesale market in that period."*

The reality is that the May 2023 Decision Paper made no such finding. Instead, it referenced an earlier Authority paper, its October 2021 Information Paper titled 'Market monitoring review of structure, conduct and performance in the wholesale market', where it claimed such a finding was made.[22]

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[18] What we're doing about the electricity price spike, Electricity Authority, August 2024, link
[19] Review of Winter 2024, Electricity Authority, April 2025, link
[20] https://www.energynews.co.nz/news/electricity-supply/816534/ea-seeks-more-power-require-information
[21] Options Paper, para 2.10
[22] Market monitoring review of structure, conduct and performance in the wholesale market – Information Paper, Electricity Authority, October 2021, link

Again, the reality is that earlier paper made no such finding. The key findings from the Information Paper appear on pages 3 to 4 and are reproduced in full below (emphasis added):

> *"2.1 Since the Pohokura outage in 2018, the spot market has experienced high prices, higher demand, continuing uncertainty surrounding future gas supply from Pohokura and other fields, and high gas spot prices. The climate has also generally been drier, with periods of quite low storage. The cost of carbon emissions has also increased significantly.*
>
> *2.2 During the review period, changes in underlying market fundamentals have been reflected in spot price movements. This is confirmed by our regression analysis (see Appendix A for details). Table 1 sets out the underlying conditions for different months from January 2019 to June 2021.*
>
> *2.3 While spot price movements appear to have reflected underlying conditions, there has been an overall increase in the level of spot prices above the level explained by the market fundamentals in the regression. The regression analysis shows that there has been a sustained upwards shift in prices after the Pohokura outage in October 2018. Since then, the market has continued to experience uncertainty around gas supply from Pohokura and other fields.*
>
> *2.4 This sustained upwards shift is indicated by the statistically significant coefficient for a dummy variable in the regression analysis. The dummy variable equals zero before the 2018 Pohokura outage, and one from October 2018 onwards. Since other underlying fundamentals are controlled for in this regression analysis, the significant dummy variable shows that the price is higher for other reasons.* ***However, what the regression analysis does not show is whether this upwards shift is due to the uncertainty surrounding gas supply from Pohokura and other fields (above that reflected in the gas spot price) or if there is some other reason for the upwards shift, such as the exercise of market power****."*

This was the Authority's actual finding i.e. that the Authority's regression analysis was inconclusive as to whether the upwards shift in price was due to uncertainty about gas supply (in relation to which the Pohokura outage was the first taste of the issues which have since weighed heavily on the sector for a number of years) or whether it was due to other reasons.

This actual finding was then distorted by the Authority's own quotation of itself which placed less and less emphasis on gas issues and the gas sector, and more and more emphasis on unsubstantiated speculation about the exercise of market power.

For example, the Authority's related 'Summary Paper' summarised the Information Paper and, while still recognising that there might be benign explanations for the price increases, made the first suggestion that prices might not be being determined in a competitive environment:[23]

> *"Prices over the review period have, at least to some extent, reflected underlying supply and demand conditions, which is a sign of a competitive market. Over the review period, demand has been higher; hydro inflows and storage have been low; there have been a number of gas production outages; and all fuel costs — including the value of stored water and the cost associated with carbon dioxide emissions — have been rising. These have all affected electricity spot prices.*
>
> *However, some of the price increases since the Pohokura outage appear to be unexplained by these underlying conditions. For example, prices tend to increase as the duration of low storage increases. However, in 2019 there was low storage for only about 4 percent of the year but an average yearly price of above $100/MWh (see Figure 4 in the main review paper). This could be because, given*

[23] Market monitoring review of structure, conduct and performance in the wholesale market – Summary Paper, Electricity Authority, October 2021, link

the data available to the Authority, it is difficult to account perfectly for all underlying conditions, or it could be because prices are not being determined in a competitive environment."

The Authority's website commentary related to the above documents and a webcast presentation made at the time by the Authority's then Chief Executive (both still on the Authority's website) took the mischaracterisation further and claimed the Authority found actual evidence of manipulation of market prices. The website commentary for example says:[24]

"Our review found out that higher prices over the review period did not always match the relative supply and demand conditions. There was also some evidence that generators may have manipulated prices by manipulating levels of supply and demand."

It is important that a regulator like the Authority accurately quotes and does not distort its findings. Consumers, Meridian and market participants more generally, place great store on what the Authority says. However, the bigger issue, as indicated above, is that the Authority's 'market power' explanation for much of the price increases seen in the last seven years has meant it has not adequately scrutinised, warned about, or used its regulatory powers in respect of the emerging demise of the gas sector. We, like the Authority in its recently released Winter 2024 Review, consider that these gas shortages alongside the drought were the drivers of the events of August 2024. The parties that were initially considered to have exercised market power, made less, not more money as a result of the events of 2024. One can reasonably assume that had market power actually been exercised, that would not have been the outcome.

2.5 The Authority's concept of a level playing field seems to deny that market participants should face the consequences of their own strategic choices

The Authority's proposed intervention is premised on the idea that the current "playing field" between generator-retailers and independent generators and retailers is not level. It is not clear to Meridian how that is the case.

Different retailers have adopted different approaches to managing wholesale market risk and to developing offerings that will appeal to New Zealand consumers. These are choices which every retailer is free to make. Some participants, such as Meridian, have chosen to vertically integrate to manage wholesale market risk on behalf of their customers – as detailed in Appendix B, there are clear strategic reasons for making such a decision. Other retailers have opted to operate without generation support but instead utilise the options available on the hedge market to manage this risk. Again, this is a deliberate and strategic choice.

Some of the independent retailers that operate in New Zealand also participate in electricity markets overseas and have adopted a vertical integration strategy in those locations. Retailers are free to commit their resources to adopt a vertical integration strategy in New Zealand too if this is what they consider is best for their shareholders and their customers.[25]

There is an important distinction to be made in seeking a level playing field in order to ensure that all participants can enter a market and make decisions on how they would like to compete,

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[24] https://www.ea.govt.nz/projects/all/review-of-wholesale-market-competition/consultation/review-of-structure-conduct-and-performance-in-the-wholesale-electricity-market/

[25] Meridian itself adopted a vertically integrated structure when it entered the Australian electricity retail market, owning three small hydro stations and two wind farms and amassing a customer base of nearly 200,000 customers at the time the Meridian Energy Australia business was sold to Shell Energy and Infrastructure Capital in 2022.

versus seeking to curtail the competitive advantages (or nullify the competitive disadvantages) that firms are experiencing as a result of their strategic decisions.

This distinction was discussed previously by NERA in a report prepared for Meridian:[26]

> *"The…aim to ensure independent retailers can compete on a level playing field appears on its face to be an uncontroversial objective. However, there is an economic difference between "levelling the playing field":*
>
> > *a. Before firms make their business model and investment decisions; and*
> >
> > *b. After firms make their business model and investment decisions.*
>
> *There is a risk that "levelling the playing field" after firms make their business model and investment decisions effectively amounts to "changing the rules of the game" in favour of one business model over another. In respect of electricity supply, risk management is fundamental to competing, and is a cost of doing business, incurred by both incumbents and entrants. Some firms choose to manage risk by vertically integrating (i.e., investing in generation) and others choose not to. Care is needed that any attempts to "level the playing field" do not:*
>
> > *a. Undermine the efficiencies the vertically integrated firms anticipated when making their investments, as this would deter future investment; or*
> >
> > *b. Give a "leg up" to firms that have opted not to make the investments, if "giving a leg up" could result in social costs (e.g., deterred investment that would have been efficient)."*

These considerations remain relevant in the current context: in contemplating the need to 'level the playing field' the Authority should not prefer one business model over another or seek to advantage one type of participant over another. This critical point was also observed by Carl Hansen:[27]

> *"For many years I have viewed the entry of non-integrated retailers as a contest between business models: a contest between gentailers with their large customer base and long-lived generation assets versus the nimbleness of new entrants with new technology and marketing ideas. When I was a regulator, it was never a case of viewing one model as better than the other, or that the absence of one signalled the market wasn't working. It was up to the market to decide whether one model wins, or they coexist."*

We agree with Mr Hansen's view: it is the choice of each new entrant and each incumbent how to best manage risk, compete with their rivals, and win customers. And it is up to the market to determine which approach ultimately succeeds. Ultimately, it can only result in greater costs for consumers if New Zealand were to subsidise or support inefficient business models.

2.6 Experience in the United Kingdon suggests fixating on retailer entry can ultimately cost consumers

NERA have drawn on their experience in the United Kingdom's electricity market to identify potential lessons for the current New Zealand context. The United Kingdom experience is particularly relevant as they have also adopted 'non-discrimination measures' in their pursuit

[26] Problem definition underlying "Internal transfer prices and segmented profitability reporting" consultation paper – memo, NERA, May 2021, link
[27] CSA, Section 6

of retail market competition. A detailed description of the United Kingdom's experience of retail market regulation is set out in Section 7 of NERA's report.

The key lessons that NERA draws from this experience are:

(a) The availability of hedging products is correlated to higher retailer entry, but at a cost to the parties mandated to make products available;

(b) Without regulatory oversight, new entrant retailers have incentives to adopt risky short-term hedging strategies to compete on price with incumbents; and

(c) Fixating on retailer entry without ensuring sustainability in new entrant business models may end up creating more costs for customers than the benefits of competition and innovation that new entrants may drive.

NERA notes that, following the exit of 29 retailers from the market in 2021, United Kingdom regulator Ofgem conducted a review of its historical policy of promoting growth in retail competition, concluding:[28]

> *"The focus on expanding competition and promoting choice, while benefitting consumers through lower prices, ultimately led to low financial barriers to entry and light regulation of financial risks. The energy crisis exposed problems with this retail market model, leading to a large number of supplier failures towards the end of last year, ultimately costing all consumers through higher bills."*

While the United Kingdom context differs from New Zealand, this experience suggests a single-minded focus on promoting new entrants can ultimately cause significant costs for consumers if other risks are not properly considered.

3 Issues with the Authority's problem definition and evidence base

This section sets out our view on the Authority's problem definition and the evidence underlying its proposal. We recognise that, to date, the Authority has developed its proposal under tight timeframes and with limited input from wider stakeholders. Nevertheless, our view is that a well-considered problem definition remains a critical part of a robust regulatory development process.

3.1 The Authority's problem definition is unclear and is not well evidenced

Section 3 of the Options Paper discusses a number of concerns the Authority has identified under the heading 'Problem Definition'. These include:

(a) Concerns about the impact of vertical integration on competition;

(b) Concerns about the availability of and access to flexible resources;

(c) Concerns about the gap between ASX futures prices and the long-term cost of new build; and

(d) Concerns about the disconnect between Internal Transfer Prices (ITPs) and retail pricing.

[28] Statutory Consultation: Strengthening Financial Resilience, Ofgem, November 2022

It is not particularly clear from the Authority's description how these concerns are related or which specific concerns the Authority is setting out to address. We discuss each of these concerns in turn below.

3.1.1 Concerns about the impact of vertical integration on competition

The Authority notes at the outset of Section 3 that it "is investigating level playing field measures to address risks to competition arising from Gentailer vertical integration".[29] This section goes on to make a number of observations about competition in the electricity market (emphasis added):

(a) The generator-retailers have sustained high retail market shares, while growth of competing retailers has been stagnant since 2021;[30]

(b) The four generator-retailers have continued to have high market shares for generation and there have been recent attempts to consolidate;[31]

(c) The limited growth of competing retailers and generators **suggests** there may be barriers to entry and/or expansion in retail and generation;[32]

(d) While efficiencies may arise from vertical integration, these **could be** outweighed by conditions or conduct that compromise the ability of non-integrated generators and retailers to compete;[33]

(e) **Where [risks to competition from vertical integration] are observed in practice**, hedge contract buyers (especially independent retailers and generators) cannot be confident that the shaped hedges they need will be available (liquidity), will be competitively priced, or that they will be treated even-handedly;[34] and

(f) These risks of vertical integration **may** persist absent a change in market structure or introduction of Level Playing Field measures.[35]

We note that much of the Authority's reasoning on these matters (as highlighted by the emphasised wording) is observational or speculative in nature. The Authority has not attempted to robustly understand or evidence the actual drivers of current market dynamics or the presence of any genuine barriers to competition. Rather, it has identified some general competition concerns or risks based on a few high-level indicators and appears content to move forward on this basis.

Carl Hansen draws attention to the Authority's lack of rigour in seeking to understand the problem. On the matter of generator-retailers seeking to restrict retail competition, Mr Hansen noted:[36]

> *"Surprisingly, the Options paper makes no effort to explain why gentailer opportunities and incentives (supposedly) changed suddenly in or around 2020 and offers no evidence regarding opportunities and incentives."*

[29] Options Paper, para 3.1
[30] Options Paper, para 3.13
[31] Options Paper, para 3.14
[32] Options Paper, para 3.15
[33] Options Paper, para 3.21
[34] Options Paper, para 3.24
[35] Options Paper, para 3.25
[36] CSA, Section 2.3

Mr Hansen undertakes his own analysis of this issue. He identifies that the trajectory of real household energy prices in recent years is not consistent with a sudden weakening of retail competition from 2020 (as suggested at para 3.15 of the Options Paper). He goes on to present an alternative explanation for why non-integrated retailers have recently found it difficult to compete effectively, which is to do with weaknesses in their business model. This is discussed in detail in Section 3 of Mr Hansen's expert report.

In summary, Mr Hansen considers the key issue is that non-integrated retailers are poorly placed to offer long-term price smoothing services to consumers as they do not own assets or have capital structures that enable them to 'ride through' a supercycle. Mr Hansen notes this explanation is consistent with non-integrated retailers being able to compete effectively before 2020 and weakly since then. We consider Mr Hansen's expert analysis makes clear that there are valid alternative explanations for the trends the Authority has observed.

3.1.2 Concerns about the availability of and access to flexible resources

The Authority goes on to say it has identified specific concerns in the New Zealand market around availability of flexible resources.[37] The subsequent discussion in the Options Paper appears to be largely based on the findings of MDAG. In discussing access to flexibility, the Authority notes some of the concerns it raises "have both a scarcity and a competition risk component to them, and it has been difficult to draw an exact line between the two".[38]

Again, this seems to be an acknowledgement that the Authority has not clearly identified the extent of the competition concern and whether there might be alternative explanations for limited availability in the supply of hedge products backed by flexible resources. It nevertheless goes on to say *if* it considers that the sharing of flexible resources is occurring in a manner that is harming competition it can use regulation to recalibrate how this is occurring.[39]

The Authority then goes on to describe the findings of its Risk Management Review.[40] We will not repeat the full list of findings here; rather we highlight three of the key findings and discuss each of these in turn:

Key finding 1: Prices for OTC baseload and peak hedge contracts are likely to be competitive

We agree.

Key finding 2: It is not clear that pricing for OTC super peak products is competitive as they trade at a substantial unquantified premium over ASX baseload prices adjusted for shape

Our expert advisors NERA further examined this conclusion. NERA note that, in comparing offered prices for super peak hedges with a calculated 'competitive' super peak price, the Authority was only able to quantify two of the six potential risk premium adjustments they had identified. As pointed out by NERA, the Authority repeatedly notes that the result of this is that the 'competitive' OTC prices (against which they compare offered super peak prices) will likely be underestimated.[41]

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[37] Options Paper, para 3.27
[38] Options Paper, para 3.34
[39] Options Paper, para 3.35
[40] Options Paper, para 3.39
[41] Reviewing risk management options for electricity retailers – Issues Paper: Appendix A, Electricity Authority, November 2024, link, paras 4.11, 4.16, 4.18 and 4.21

The Authority also notes that these unquantified risk premia "could have a big impact on super-peak contract prices" with this impact likely to be increasing over time.[42] As a result, NERA observes that rather than being "exhaustive but inconclusive", the Authority's analysis is simply "incomplete".[43]

NERA concludes:[44]

> *"Given the uncertainty of the nature and scale of the drivers of these concerns, the EA should ensure that any interventions are appropriately targeted and proportionate, and thus do not create unintended consequences that may exacerbate the problems they seek to solve."*

Carl Hansen also examined the Authority's conclusions with respect to the pricing of super peak products. He notes that analysis in the Authority's paper 'Reviewing risk management options for electricity retailers – Issues Paper' (**RMR Issues Paper**) reveals there is little practical difference in terms of risk management benefits from hedging with baseload and peak products (both of which the Authority concludes are competitively priced) versus hedging with baseload, peak and super peak products. In Mr Hansen's own words:[45]

> *"…the Issues paper shows that adding a super-peak hedge to a portfolio of baseload and peak hedges provides minimal additional cover for a [non-integrated retailer]."*

Mr Hansen also argues that, if any party firmly believed that super peak hedges are materially over-priced, there would be nothing to stop them from selling those products and reaping the benefits when spot prices during super peak periods turn out lower than their hedge price. Mr Hansen considers it is not credible for the Authority to believe it has identified opportunities for excess profits, publicised them, and yet speculative activity has not reduced the gap. As a result, he goes on to conclude:[46]

> *"…the concerns about super peak prices are neither material nor credible".*

Considering these factors, with respect to the key finding of the Risk Management Review (that it is not clear that pricing for OTC super peak products is competitive) we can conclude:

(a) The Authority has not been able to confirm that pricing of super peak products is uncompetitive as it has not undertaken the analysis to quantify all the potential risk premia which would be reflected in those prices;

(b) The lack of speculative activity to reduce the gap of any over-pricing of super peak products suggests they may, in fact, be competitively priced; and

(c) Regardless of the competitiveness of super peak pricing, independent retailers have access to hedge products (baseload and peak) which:

   (i) The Authority has confirmed are likely to be competitively priced; and

[42] Reviewing risk management options for electricity retailers – Issues Paper, Electricity Authority, November 2024, link, para 2.7

[43] These conclusions are similarly supported by the findings of Sapere in their expert report for Contact to the Authority's Risk Management Review. Sapere found "very strong evidence that the current challenges in the supply of super peak products are driven by reduced firm capacity in the market relative to demand, and little evidence to support the hypothesis of market power". See link

[44] NERA, Section 2.1

[45] CSA, Section 2.2

[46] CSA, Section 2.2

(ii) The Authority's own analysis suggests would offer substantially the same risk management benefits as a portfolio which incorporates super peak products.

Key finding 3: While the evidence points to fuel or capacity scarcity being the driver behind the current thin and illiquid market for shaped hedge cover "there is also a plausible driver that has competition implications (for example, refusing to supply products on appropriate terms to counterparties who are downstream competitors), indicating that some level of market power could have been in play."

The Authority is again deriving a conclusion based on speculation rather than on clear evidence. The Authority revisited its conclusions on this matter in 'Reviewing risk management options for electricity retailers: Update paper following submissions' (**Update Paper**) where it found:[47]

> *…no evidence has been provided that causes us to definitively conclude that the exercise of market power to reduce competition is occurring. However, the risk that market power is being exercised remains clear. While some submitters argued that scarcity is the primary driver, the presence of scarcity does, in itself, not exclude the possibility of market power being exercised – both may exist.*

This statement makes it clear the Authority does not have evidence that the exercise of market power is occurring. It is merely speculating that this is possible.

We note also the Authority provides an example of generator-retailers "refusing to supply products on appropriate terms to counterparties who are downstream competitors" as a potential driver of the thin market for shaped hedge products. Little evidence is provided of such behaviour except (from what we can tell) in a footnote in the RMR Issues Paper which cites generator-retailers choosing not to respond to particular RFPs due to limited commercial interest or because they considered they were unlikely to offer a competitive price.[48] For our part, Meridian's practice is always to respond to RFPs from independent retailers. As such, the Authority's claim is inconsistent with our experience.

In the same paragraph in the RMR Issues Paper the Authority also acknowledges that generator-retailers' decisions not to respond to RFPs:

> *"…could be due to location factors, our nodal market, geographically concentrated generators, or the inability to get the necessary financial transmission rights within the RFP timeline".*

Again, the Authority has not reached a firm conclusion here and freely acknowledges there may be non-competition-related reasons for the behaviour it observes. Despite this, the Options Paper goes on to cite "withholding of supply" along with other matters (which we would also dispute) as part of the evidence from the Risk Management Review:[49]

> *"The evidence, particularly from the Risk Management Review, raises genuine concerns that this risk may be playing out — withholding of supply, over-pricing, favouring supply to internal channels over external competitors."*

This statement seems to mischaracterise the findings of the Risk Management Review, presenting inconclusive analysis and speculation as evidence.

[47] Reviewing risk management options for electricity retailers: Update paper following submissions, Electricity Authority, February 2025, link

[48] RMR Issues Paper, para 5.3(b) of Chapter 7

[49] Options Paper, para 3.51(b)

3.1.3 Concerns about the gap between ASX futures prices and the long-term cost of new build

The Options Paper also refers to an ongoing gap between the forward curve derived from ASX hedge prices and the cost of new generation build and notes that some parties have concluded from this that there are barriers impacting the extent or effectiveness of new entry or expansion that would close the gap.[50] The Authority does not identify who those parties are or whether the Authority itself shares this view. It goes on to note that there may be a range of alternative factors which explain this gap including material market uncertainties at various points (for example, gas supply uncertainty, whether the Tiwai Pt aluminium smelter would continue to operate, the previous Government's proposed Lake Onslow pumped hydro scheme), and investment lag.

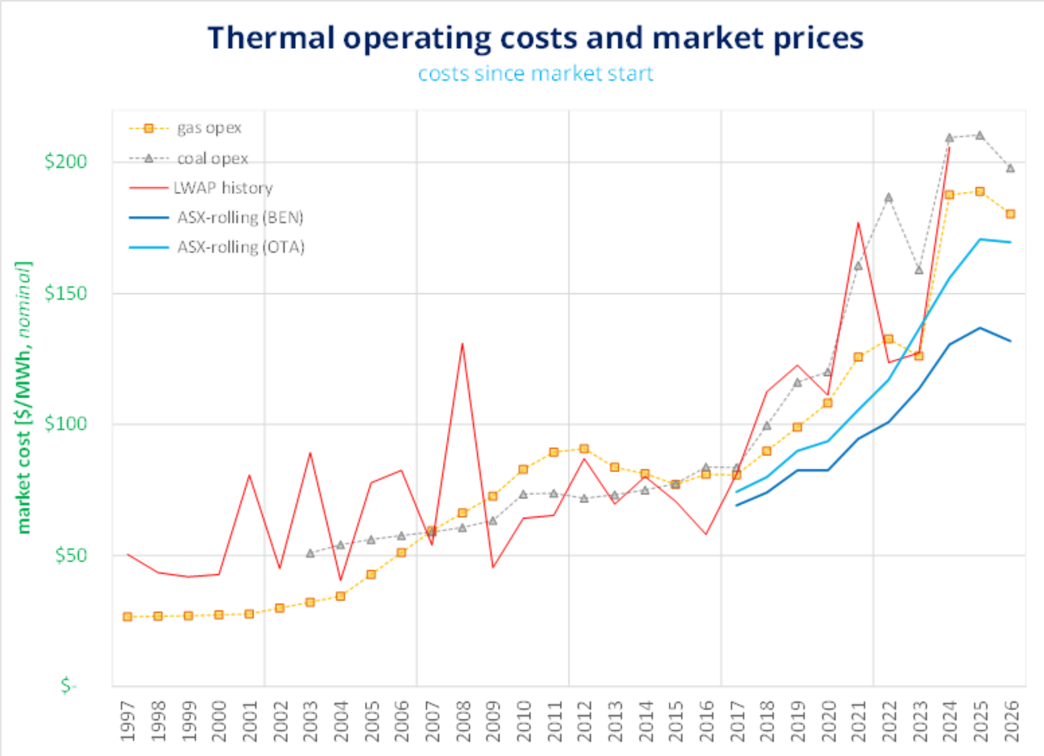
Meridian agrees that all these alternative factors are likely relevant to the observed gap between ASX prices and new build cost. Meridian also reminds the Authority of its previous conclusions in its May 2023 Decision Paper stating that:[51]

> *"Over time, it is anticipated that investment in new renewable generation will bring prices back down to the cost of new supply. The Authority set out in the Issues Paper how the observed lag between price signals and new investment is in part linked to the time it takes to build infrastructure and factors such as consenting requirements, COVID-related supply chain issues, and cost escalation. But it is also linked to investment-impeding uncertainty around the NZ Battery project, the Gas Transition Plan, and the Energy Strategy, and insufficient commercially-viable renewable solutions to firm intermittent supply. Having considered submissions, the Authority is satisfied with this explanation of the observed lag..."*

Gas market uncertainty – beginning with the Pohukura outage in 2018 and continuing until the present day – has had as significant an impact on ASX prices as it has on wholesale electricity prices.[52] This can be readily seen by examining the correlation between gas costs and electricity prices, as set out in Figure 2. There is evidently a strong correlation between thermal fuel costs and electricity prices, suggesting higher fuel costs are the primary driver of recent elevated ASX prices rather than any underlying competition issues in the wholesale market.

[50] Options Paper, para 3.41
[51] Promoting competition in the wholesale electricity market in the transition toward a renewables-based electricity system – Decision Paper, Electricity Authority, May 2023, link
[52] https://www.mbie.govt.nz/about/news/natural-gas-production-continues-to-decline

Figure 2: Relationship between thermal fuel costs and electricity prices



Source: Meridian

Carl Hansen also examines the implicit comparison contained in Figure 4 of the Options Paper and concludes that this comparison is not being made on a like-for-like basis:[53]

> *"The chart shows hedge prices peaking in 2023, at about 75% higher than the upper estimate of cost, declining to about 30% by August 2027. However, these price-cost margins must be interpreted carefully because the hedge prices are only for 2-4 years ahead, whereas the LRMC estimates are the average cost of energy over a plant's entire life. For example, solar and wind plants last 25-35 years, and many baseload plants last far longer. In essence, the chart is comparing 'apples and oranges."*

It is not entirely clear from the Options Paper what weight the Authority has placed on its observation regarding the gap between ASX prices and the cost of new build or how this has factored into its thinking regarding the level playing field proposal. But the fact that the Authority has chosen to refer to this in the Options Paper suggests it at least considers it relevant. Meridian's view is that a more robust consideration of the drivers of recent ASX prices and how they relate to new generation build costs is needed before inferring any competition concerns from this comparison.

3.1.4 Concerns about the disconnect between ITPs and retail pricing

The Options Paper goes on to discuss generator-retailer ITPs, noting there is an underlying issue that they are not currently set on a basis that would allow the Authority to make a meaningful comparison between how generator-retailers treat themselves compared to how

[53] CSA, Section 2.1

they treat third parties. The Authority notes “this disconnect between the ITPs and retail pricing suggests there may be an uneven playing field”.[54]

Again, the Authority frames its concern here as a suggestion and it is not clear what the specific market failure might be. It is true, as the Authority suggests, that:[55]

> *“…gentailers’ vertical integration means their retail arms may not be exposed to the same choices, risks and costs faced by non-integrated retailers.”*

This is a consequence of the strategic decision that generator-retailers have made to vertically integrate and, in contrast, the decision that non-integrated retailers have made not to do so. This in itself is not a reason for intervention.

The Authority goes on to say that these risk management benefits are “an understandable driver of the decision to vertically integrate” but “when that integration then aggravates competition concerns, it necessarily invites closer regulatory consideration”.[56] The Authority is again referring to general competition concerns without defining this further or providing specific evidence.

3.1.5 Overall views on the Authority’s problem definition

The Authority has not provided a clear, singular problem definition statement. It has discussed a range of general competition concerns relating to generator-retailer structure and ultimately concluded that “the competition risk is clear”.[57] We disagree. We do not consider that the Authority has adequately defined the problem.

Many of the Authority’s concerns are speculative and appear to be based on a hunch or the views of “some parties”. It is clear in a number of cases that the Authority has not been able to differentiate between genuine competition concerns and other factors (such as scarcity, fuel shortages, policy uncertainty, and investment lag). The Authority also appears to have ignored – or at least has not sought to understand:

(a) potential alternative explanations for the high-level trends it has observed e.g. the fact that non-integrated retailers have poor long-run price-smoothing capabilities relative to incumbent generator-retailers; or

(b) evidence that is not consistent with its competition concerns e.g. the decline in real terms in the cost of the energy component of energy bills since 2020.

The Authority has mischaracterised the findings of its own Risk Management Review, noting concerns such as “withholding of supply, over-pricing, favouring supply to internal channels over external competitors” when, in fact, the Risk Management Review:

(a) Determined pricing of baseload and peak products was likely to be competitive;

(b) Determined it is *not clear* that pricing for OTC super peak products is competitive; and

(c) Did not reach firm conclusions on the existence of withholding, noting that a lack of responses to some super peak RFPs “could be due to physical withholding” or “could be due to location factors, our nodal market, geographically

[54] Options Paper, para 3.45
[55] Options Paper, para 3.45
[56] Options Paper, para 3.45
[57] Options Paper, para 3.51

concentrated generators, or the inability to get the necessary financial transmission rights within the RFP timeline."[58]

Meridian's view is that the Authority's problem definition is vague, lacks robust evidence and is, at times, misleading. It does not establish a convincing basis for subsequent intervention.

The Authority states in the Executive Summary of the Options Paper that "while evidence of Gentailers exercising market power is not clear-cut, the liquidity and pricing risks are clear". It is concerning that the Authority appears to acknowledge a lack of compelling evidence but seems prepared to move forward on the grounds that there are 'risks'.[59]

The potential impacts of proceeding on this basis are set out starkly by Carl Hansen (emphasis added):[60]

> *"I am very concerned the Task Force has mis-diagnosed the problem confronting non-integrated retailers and does not appear to have fully considered important factors, such as asymmetries between the hedge and retail markets and retail pricing in the face of repeated adverse supply shocks, that were thought more temporary than has turned out to be the case.* ***In my view, this is leading the Authority to propose options that are likely to materially increase prices for households and businesses.*** *It could also harm non-integrated retailers in the long run. Both are unnecessary."*

3.2 It is not clear that Meridian's submitted evidence has been considered

The Authority notes at various points in the Options Paper that it has not been presented with evidence which has caused it to reconsider the conclusions it reached in its Risk Management Review. For example:[61]

> *"While submitters put forward a range of views for and against these findings, parties that disagreed did not present further data or specific evidence to support these views, despite having the best access to relevant information."*

While Meridian did not submit additional evidence with its submission on the Risk Management Review, this was primarily because we had provided substantial evidence on our approach to offering and pricing hedge contracts to the Authority during the information gathering phase of the review.

This included:

(a) A Word document setting out a detailed description of our methodology for pricing shaped products to independent retailers;

(d) An Excel document setting out a worked example of a specific, recent real-world implementation of the above methodology, including the historical price series which fed into the calculation.

We were therefore somewhat surprised by the Authority's statements about not receiving specific evidence and sent a query to the Authority on 1 April 2025 asking what further

[58] RMR Issues Paper, para 5.3

[59] It is also concerning that in some cases the Authority appears to acknowledge that particular issues are only "alleged" but nevertheless appears to draw conclusions on these matters. For example, paragraph 3.40 of the Options Paper notes that "the Risk Management Review issues paper did not make any preliminary findings regarding whether there is a margin squeeze (as alleged by independent retailers)" while paragraph 3.46 goes on to conclude "In an environment where level playing field and margin squeeze concerns have been raised, the existing approach to ITPs is not fit for purpose".

[60] CSA, Section 1

[61] Options Paper, para 3.47

evidence the Authority had hoped to receive. The Authority wrote back to us on 17 April 2025 noting that the further evidence it was seeking was "anything to further elucidate/clarify the other premia" that was discussed in Appendix A of the RMR Issues Paper.

It is not clear to us whether this is the first time the Authority has engaged with the particular evidence that Meridian has previously provided. We would agree that it is important for the Authority to understand the potential composition and magnitude of the various risk premia that apply to shaped products. This point was well made by our expert advisors NERA, as described above in Section 3.1.2. If the Authority has not understood the various risk premia that are likely to be factored into the pricing of a shaped hedge product, it is not possible to robustly draw conclusions on the competitiveness of any market pricing.[62] This is particularly important where a subsequently proposed intervention is based on the conclusions formed from this analysis – as is the case here.

We are concerned that the Authority is still gathering and analysing evidence on the nature and extent of the problem of the competitiveness (or otherwise) of the market for super peak products yet, at the same time, has moved rapidly down the path of proposing an intervention which will have wide-ranging implications and brings significant risk of unintended consequences.

Due to the limited time available between the Authority's response to our query and the closing of submissions, we have not sought to attach any additional 'evidence' to this submission. However, we remain happy to work with the Authority to provide any relevant information on our approach to offering and pricing hedge contracts if it will help inform the Authority's assessment of these issues.

3.3 The decision to intervene now appears rushed and is inconsistent with MDAG's recommendations

The Authority views its proposed staged approach to level playing field measures as incorporating (or "subsuming") a version of virtual disaggregation, an intervention originally conceived of by MDAG.[63] More specifically, MDAG had recommended that virtual disaggregation be developed as a backstop measure – to be 'put in the drawer' ready for use if other measures are not effective. In the Authority's own words, virtual disaggregation was intended to address "a specific future market power concern".[64] MDAG's Options Paper envisioned that such a measure could be in place by 2029.[65]

The Energy Competition Task Force initially took a similar view to MDAG, with its early call for feedback on level playing field measures noting that they were to be used "as a regulatory backstop if earlier steps are not effective".[66] However, the Option Paper notes that rather than treating level playing field measures as a future backstop option, the Authority is now proposing an immediate staged introduction of level playing field measures in the form of non-

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[62] For example, it is not possible for us to determine at this stage which of the various hedge prices offered by Meridian and included in the new analysis shared by the Authority in its 17 April response to us were offered at a time when Meridian was capacity or energy constrained. This would influence our approach to pricing specific hedges and may explain higher prices observed in the Authority's data.
[63] Options Paper, para 2.33
[64] Options Paper, para 2.31(b)
[65] Price discovery in a renewables-based electricity system – Options Paper, MDAG, December 2022, link, p26
[66] https://www.ea.govt.nz/news/general-news/energy-competition-task-force-request-for-level-playing-field-measures/

discrimination obligations.[67] The Authority notes in this same paragraph that it discusses "the reasons for this change in approach in detail in Chapter 6 of this paper".

It is not clear to us where this discussion is located in Chapter 6, other than a brief further description that the Authority's "current view is that there are good reasons to consider introducing a proportionate Level Playing Field measure in addition to the standardised flexibility product and PPA initiatives".[68]

It is also not clear to us what has changed between MDAG's conclusions and the Task Force's current consideration of level playing field measures which warrants this accelerated timetable – or indeed what has changed since the inception of the Task Force (when such measures were still intended to be a 'regulatory backstop') and now. In addition to the lack of evidence discussed in Section 3.1 above, it appears this decision is being rushed. Our view is this risks falling short of a robust regulatory development process.

There are also wider developments which may have consequences for the timing and suitability of the Authority's proposal. As the Authority is aware, the Government has commissioned a wide-ranging review of the sector which will include the following as particular matters to be addressed:[69]

(a) How does business ownership, structure or design of markets affect incentives or opportunities to invest in generation, storage, transmission and distribution?

(b) What is the impact of market design and market rules on competition, market entry and expansion?

Both of these questions could feasibly include consideration of the merits of vertical integration and are likely to take a wider view of this matter than the competition-focused perspective adopted by the Task Force. The review is currently expected to report in June. As this is just a matter of months away – and given the potential consequences and impacts of progressing an intervention such as that proposed by the Authority – it would seem sensible to await the findings of the Government Review to determine if the respective recommended courses of action are aligned before committing to a particular path.

3.4 The proposed solution is more wide-ranging than is justified by the evidence in the Risk Management Review

As noted in Section 3.1 above, the key findings of the Authority's Risk Management Review included:

(a) prices for OTC baseload and peak hedge contracts are likely to be competitive; and

(b) the same conclusion could not be reached for OTC super-peak hedge contract prices as they trade at a substantial unquantified premium over ASX baseload prices adjusted for shape.

In concluding the second point, the Authority noted that "the evidence does point to scarcity being a driver" but said:[70]

[67] Options Paper, para 2.34
[68] Options Paper, para 6.2
[69] Terms of reference for a review of electricity market performance, MBIE, February 2025, link
[70] Options Paper, para 3.39

> *"…there is also a plausible driver that has competition implications, eg, refusing to supply products on appropriate terms to counterparties who are downstream competitors, indicating that some level of market power could have been in play."*

We have already discussed the speculative nature of this conclusion in Section 3.1 above but – ignoring this for the moment – it is clear from the Risk Management Review findings that the *only* concern the Authority has identified is in relation to the pricing of super peak products. However, the Authority's proposal as currently written will capture *all* hedge contracts offered by generator-retailers, including those the Authority has confirmed are likely to be trading competitively.

The Authority notes in the Options Paper that "it would be more effective for any non-discrimination obligations to cover all hedge contracts", citing risks of discriminatory behaviour for the remaining hedge products.[71] The brief subsequent discussion on this point underplays the fact that the Authority's proposal is a significant departure from its conclusions on the scale and nature of the problem as set out in the Risk Management Review. Our expert advisor Carl Hansen made a similar observation, noting "it seemed odd the Authority was proposing a wide-ranging intervention to address a narrow hedge market issue" identified in the Risk Management Review.[72]

In our view, this significant broadening of the scope of the intervention is inconsistent with a robust regulatory development process and only heightens the risk of unintended consequences without any underlying justification. If the Authority is confident that the analysis in its Risk Management Review remains robust, then a more proportionate and reasonable response would be to focus its intervention on ensuring a competitive and liquid market for super peak products. Such an alternative is discussed further in Section 5 of this submission.

4 Our views on the proposal

4.1 The proposal will effectively deliver vertical separation or disaggregation

The Options Paper states:[73]

> *"We respect the right of businesses to choose their own structure and form their own view of the benefits of different structural options. We prefer to not unnecessarily restrict this choice."*

The Authority also frames its preference for principles-based non-discrimination obligations as "the lower end of potential interventions".[74] However, as discussed by NERA in their expert report, the proposal would deliver the effects of virtual vertical separation.[75]

Virtual vertical separation would be a significant intervention given the benefits of vertical integration discussed in Appendix B of this submission and the consistent conclusions in the academic literature that where vertically integrated firms are forcibly separated, there is solid evidence from a variety of sectors around the world that this harms consumers.

The Authority's proposed principles would not be structural separation, but they would erode several of the key benefits to consumers associated with vertical integration. Most notably:

[71] Options Paper, para 6.7
[72] CSA, Section 1
[73] Options Paper, para 3.19
[74] Options Paper, para 3.51(e)
[75] NERA, Section 4

(a) generator-retailers will incur transaction and compliance costs to put in place a portfolio of notional internal hedges that are less efficient than the absence of such arrangements under vertical integration; and

(b) those notional contracts will decrease the stability of the retail segment of each generator-retailer and lead to more volatile retail prices and less retail competition (as discussed further below).

Carl Hansen made a similar and related point:[76]

> *"Although the paper states that the Authority respects the right of businesses to choose their own structure and prefers to not unnecessarily restrict those choices (3.19), it is in fact proposing very significant restrictions. Although it may not think so, the Task Force is effectively requiring gentailers to take a short-term approach; that is, to adopt the inherent limitations of the non-integrated model. It is overturning the key feature of integration, which is that it displaces the contractual approach to managing price supercycles."*

4.2 There is already a level playing field

The Authority proposes "level playing field measures". In summary, the proposal would require generator-retailers to pretend they have internal contracts and base those implicit contracts on observable market rates for comparable contracts.[77] The Authority is also requiring these implicit internal contracts to be priced at levels that avoid any cross-subsidy such that internal business units must be commercially viable on a standalone basis.[78] [79]

As discussed in Section 2.5 above, in Meridian's opinion, no level playing field measures are needed because the playing field is already level. It is open to any electricity retailer to pursue a capital-intensive vertically integrated business model, or a thinly-capitalised retail-only business model. There are pros and cons associated with each business model and no barriers to adopting either one.

Rather than a level *playing field*, the Authority's proposal seems to be aimed at achieving level *outcomes* by requiring that either:

(a) all businesses enjoy the benefits of vertical integration (even those who have chosen not to invest the capital to become vertically integrated); or

(b) no businesses enjoy the benefits of vertical integration (regardless of investments made to date in that business model).

We explore each of these scenarios further below but note the Authority's proposed principles do not specify one or the other, with implementation left to the discretion of generator-retailers.

These scenarios reflect the discussion in Carl Hansen's paper that picks up on the supposed disconnect between ITPs and retail pricing identified in the Options Paper and the Authority's conclusion that the existing approach to ITPs *is not fit for purpose* in an environment where level playing field and margin squeeze concerns have been raised.[80]

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[76] CSA, Section 2.5
[77] Options Paper, Appendix B, para 15a
[78] Options Paper, Appendix B, para 17
[79] We are adopting the Authority's language of a 'cross-subsidy' here. However, we believe this term mischaracterises the ability of generator-retailers to undertake long-term price smoothing, which in fact is welfare enhancing for consumers. What might be viewed as a cross-subsidy during the current phase of the market supercycle (a supply constraint) would become the opposite during the inverse phase (a supply surplus). It is the ability of generator-retailers to maintain price stability through these supercycles that consumers value.
[80] Options Paper, para 3.46

Mr Hansen notes that the Options Paper is vague regarding where the mis-pricing lies, i.e. is it on the retail or generation side of the business?[81] If the mispricing is on the retail side of the business then all retailers should price off ASX and other market prices meaning no retailers enjoy the benefits of vertical integration. If the mispricing is on the generation side, then hedges should be cheaper such that everyone enjoys the benefits of vertical integration (without making associated capital investments).

4.3 Implications if the benefits of vertical integration must be shared with all retailers

The proposed principles would lead to the sharing of the benefits of vertical integration if a generator-retailer decides to comply by putting in place a series of long-term notional contracts that attempt to capture the benefits of the vertically integrated business model.

The principles would then require the generator-retailer to make the same contract terms available to third parties – for example, as volumes roll off existing notional internal hedges and need to be renewed. In Meridian's opinion, this would amount to a 'leg up' for non-integrated firms rather than a level playing field since they would have access to the benefits of long-term hedges associated with investment in capital intensive assets but without putting any capital at risk.

The implications if the Authority expects the proposed principles to require the sharing of the benefits of vertical integration with all retailers, include:

(a) arbitrage risks to the extent any generator-retailers may need to sell hedges below prevailing market rates to make this implementation approach work in practice;

(b) gradual retail price rises for any generator-retailer implementing the principles in this way due to the inability of notional internal contracts to fully reflect the benefits of vertical integration;

(c) distortions to retail competition to the extent generator-retailers have less flexibility to respond to changing market conditions;

(d) potential uneven impacts on generator-retailers if buyers identify one generator-retailer as having the most appealing contracts for cherry picking; and

(e) chilling of generation investment.

We discuss each of these implications in turn.

4.3.1 Arbitrage risks

Generators cannot offer contracts to non-integrated retailers at prices materially below market prices without risking being arbitraged on the ASX futures market. To the extent that notional internal hedge contracts that seek to replicate the benefits of vertical integration are lower priced than ASX futures contracts then arbitrage becomes a real risk when sale of those "vertical integration replicating" contracts to others is mandated.

It is noteworthy that the Authority's proposal extends the non-discrimination obligation to cover all buyers of hedges including, it seems, banks and trading houses and other parties that have no involvement in the New Zealand energy sector except as buyers of hedges. The proposal

[81] CSA, Section 2.3

as it stands could therefore expose New Zealand businesses to arbitrage by large global financial institutions and reduce the amount of hedge cover potentially available to independent retailers.

4.3.2 Implications for household electricity prices

As described by NERA, it will not be possible for a generator-retailer to build its implicit contract portfolio using market traded hedges, without changing the implicit contract itself:[82]

> *"This is because the implicit contract is based on a very complicated relationship between the cost of its assets over their remaining lives, its long-term expectation of its customer base and expected retail tariff levels, the flexible nature of its generation fleet and customer base (e.g. demand side response), climate conditions, the known and unknown shape of demand, etc. Resolving this complexity implicitly is one of the benefits of vertical integration..."*

Vertical integration is efficient because it avoids the need to identify contracts to cover these complex and related risks. Notional internal hedges would inevitably capture the benefits of vertical integration imperfectly and over time it should be expected that vertically integrated retailers will need to increase retail prices based on these less efficient implicit internal hedges.

4.3.3 Distortions to competition in the retail market

In addition, implementation of the proposed principles in this manner could prevent generator-retailers from competing aggressively at times. Attempting to identify and lock in longer-term hedge positions that reflect the integrated business model could risk locking in the period of elevated wholesale prices since 2019. If the wholesale market reaches the end of the current super-cycle and prices begin to fall as a result of new generation investment, an integrated firm would need to continue to offer retail prices based on its long-term notional contract position meaning its retail prices would be slow to fall and there would be opportunities for non-integrated (or small integrated) retailers to win market share. Under the proposed principles, generator-retailers would have limited ability to compete on price at these times.

4.3.4 Potentially uneven impacts on generator-retailers

The relative differences in implementation across generator-retailers could also distort competition. Non-integrated retailers could seek to identify which generator-retailer had captured the most benefits of vertical integration in their implicit contract portfolio and could target purchases of those relatively more appealing contracts. Such cherry picking could result in significant competitive disadvantage to any generator-retailer that is an outlier and is targeted – particularly if an opportunity for arbitrage is identified. Any cherry-picked generator-retailer could be forced to sell a significant portion of its capacity and would need to look elsewhere for hedges to support its retail business at higher prices, accept spot risks, or shrink its retail business.

4.3.5 Chilling of investment

If the proposed principles are implemented, there will be less incentive for non-integrated retailers to invest in generation since they will have rights to access the benefits of owning generation without putting capital at risk.

Generator-retailers may also have reduced incentives to invest to the extent that new generation increases capacity headroom and necessitates further hedge volume be offered

[82] NERA, Section 4.1

to other parties. When a generator-retailer builds a flexible asset, it may do so in part to protect the retail arm from price volatility. The Authority's proposal is that generator-retailers:[83]

> *"…would no longer be able to prioritise allocation of available shaped hedges to their own retail functions as they are currently able to. Instead, they would be required to make those hedges available to all potential buyers".*

As discussed by NERA in their expert report, if a generator-retailer is unable to fully use flexible generation to offset retail risks, and does not capture the full value of the insurance it provides because it is forced to sell hedges to other firms, then this takes away a substantial portion of the value of building the generation asset, and hence reduces the incentive to build it.[84]

4.4 Implications if the benefits of vertical integration should not be enjoyed by anyone

This would be the outcome if generator-retailers decided to comply with the principles by putting in place a series of short-term notional contracts. This seems to be the implication of the Authority's statement that "internal transfer prices should be based on observable market rates for comparable risk management contracts, including baseload, peak and super-peak contracts (such as the standardised flexibility product)" given these contracts are only for around three years in duration.[85] If this is the only implementation pathway that the Authority has in mind, then it needs to urgently provide that clarification.

The arbitrage risks associated with this option are likely to be less given the availability of reference prices in the ASX New Zealand Electricity Futures market and via hedge disclosures for peak, and super peak contracts (including the new standardised product). Making contracts available to other buyers based on these reference prices would be relatively low risk. However, the implications of this implementation method are more significant in other respects, including:

(a) implications for household electricity prices which would no longer benefit from longer-term price smoothing; and

(b) distortions to retail competition related to the above; and

(c) chilling of generation investment.

4.4.1 Implications for household electricity prices

In this implementation scenario, the retail prices offered by integrated firms would need to be based on short-term contracts and would therefore be far more volatile and would immediately be higher priced than the status quo. This should be unsurprising given:

(a) price smoothing by generator-retailers has kept household electricity prices substantially lower than what would otherwise have occurred since the energy component of average residential costs has declined in real terms since 2020,[86] while ASX prices over the same period have increased; and

[83] Options Paper, para 6.40
[84] NERA, Section 6.1
[85] Options Paper, Appendix B, para 17
[86] Household sales-based electricity cost data, MBIE, December 2024, link

(b) transparent segment reporting by the vertically integrated firms shows negative retail segment EBITDAF in recent years based on internal transfer prices that, we understand, are all linked to some form of rolling baseload ASX prices.[87]

The ability of generator-retailers to offer long term price smoothing to end customers is one of the key benefits of vertical integration. It can be seen as particularly valuable during the current phase of the market supercycle (i.e. a supply constraint). There is a high risk that the Authority's proposal will erode or eliminate this benefit, driving retail prices to be higher and more volatile. While independent retailers may benefit from these changes, consumers will lose.

Carl Hansen's expert report estimates that without generator-retailer price smoothing, prices would have been 21-26% higher in December 2024, or $460-570 higher per year (in a scenario where retail businesses need to be commercially viable in any given individual year). Mr Hansen concludes that the short-term retail price risks associated with the proposal are "likely to be material for households and small businesses".[88]

The extent of immediate retail price rises by generator-retailers would be greater if it is the Authority's expectation that integrated firms implied internal hedges are matched to retail load shape using peak and super peak products (compared to the status quo of ITPs based on ASX baseload prices).

There is significant uncertainty in the Authority's proposal regarding what would amount to a cross-subsidy where a retail business is deemed not commercially viable on a standalone basis. In Meridian's opinion, if a business that has a strong enough balance sheet to ride through a commodity cycle, then commercial viability should be viewed over the long term rather than profitability in any given year. Shareholders will have varying tolerance for the duration over which a retail business should be commercially viable and the amount of short-term pain that will be acceptable. The Authority needs to urgently clarify its expectation in this regard.

4.4.2 Distortions to retail market competition

Impacts on retail market competition under this implementation scenario would likely be significant. Generator-retailers would need to increase retail prices and would expect to lose market share through switching over time. Non-integrated and smaller integrated retailers could either:

(a) gain market share (especially smaller integrated retailers like Nova, Pulse and Loadstone who are not proposed to be captured by the principles since they could continue to price smooth over a longer period and pass on the benefits of vertical integration); or

(b) raise their prices as well, since they could do so and remain competitive with generator-retailers, meaning they would likely experience less growth in market share but more revenue in the short term.

Either way, this would be a significant wealth transfer in favour of non-integrated and smaller vertically integrated retailers. This may be why there has been such strong advocacy by non-integrated retailers for rules of this kind. However, it is far from clear to Meridian that consumers would benefit.

[87] See for example Meridian Energy Limited Annual Report 2024 page 129
[88] CSA, Section 5

4.4.3 Chilling of investment

As noted in NERA's expert report, unwinding long-term retail price smoothing and forcing the adoption of more volatile retail prices would mean revenue uncertainty for generator-retailers and reduced access to finance for new generation investments.[89] Revenue reliability is critical to support investment in significant infrastructure with a long pay-back period.

4.5 A chaotic implementation is more likely than either of the above scenarios

Generator-retailers could decide to implement the Authority's proposed principles in either of the ways described above or do something in between (or do something completely different like sell their retail business).[90] A chaotic implementation is likely, and it is not clear whether implementation would result in the outcomes the Authority intends.

In Meridian's opinion, there is a high likelihood of significant distortion to the free trading of risk and unintended consequences should be expected. We cannot see how consumers would benefit.

The incentives on each generator-retailer are to develop an implied hedge portfolio that strikes a balance between implied internal contract prices that:

(a) keep their retail segment input cost low enough to avoid retail price rises; and

(b) avoid or minimise arbitrage risks by using notional contract prices that are equivalent to prevailing market rates.

Meridian sees no way to do both. There is a trade-off to be made, and each generator-retailer will implement the principles differently.

4.6 Small vertically integrated firms will have a significant competitive advantage

Regardless of how the proposed principles might be implemented, we would expect small vertically integrated firms to have a significant competitive advantage.

Assuming the proposed principles only apply to Meridian, Mercury, Contact and Genesis, smaller generator-retailers like Nova, Pulse, and Lodestone would have a competitive advantage because they would be able to continue to offer longer-term price smoothing based on their generation investments and deliver the benefits of their chosen business model to end consumers.

There is no justification for applying any proposed principles selectively to vertically integrated firms above a certain scale.

4.7 Implementation of the proposed principles would be challenging and costly

While the Authority may consider a set of six principles (and an associated compliance obligation) to be a relatively simple form of intervention, our view is that this will be a highly complex solution to implement. Complexities are likely to arise in multiple ways:

[89] NERA, Section 6.2

[90] Current business structures are not necessarily static – the Authority need only look to the Trustpower sale of its retail business or Lodestone's announcement that it intends to vertically integrate.

(a) Determining a reasonable portfolio of internal hedges, including duration, shape, quantity and price (with reference to undefined ‘observable market rates’, which do not exist for longer-term risk management based on physical assets);

(b) Identifying an objective measure of capacity headroom, which will vary significantly over time based on expected retail portfolio, contract position, generation investments and outages (both planned and unplanned);

(c) Establishing a mechanism through which to offer available capacity to internal and external parties, including frequency, format, any objectively justifiable price adjustments for external buyers, and a method for allocating volume when oversubscribed;

(d) Determining how the principles apply to new generation investments and other sources of flexible capacity (for example batteries, demand response services and virtual power plants);

(e) Assessing independent commercial viability of internal business units;

(f) Managing information flows so as to ensure equal access to internal and external parties, including managing commercially sensitive information; and

(g) Instituting a Board certification process (and associated Board reporting).

Such complexities will entail high compliance costs, risk unintended consequences, and may be less likely to achieve the Authority’s desired outcomes.

If the Authority proceeds with its proposed approach, it must do more to enable implementation and clarify its expectations. This should include the development of far more detailed guidance for generator-retailers, with worked examples of how the proposed principles could be implemented in practice. The drafting of the principles and associated guidance should also address the workability concerns that Meridian has identified in the following section.

4.8 If the Authority intends to develop this proposal further, several changes are necessary to improve its workability

In Meridian’s opinion, to make the proposal workable, the changes set out in this section would be necessary at a minimum. These changes could make the proposal more prescriptive, but they would also clarify the Authority’s intentions. That clarity would in turn enable easier implementation and proper consideration of the costs and benefits associated with the proposal.

4.8.1 Clearly specify that the standalone commercial viability of a retail segment should be assessed over several years

To assess compliance with the no cross-subsidy principle, the standalone commercial viability of a retail segment should be measured over the long term and the Authority should acknowledge this in the drafting of the principles and associated guidance. This should reflect the strength of a business’ balance sheet to ride through a commodity cycle and be profitable over the long run.

We also note that, in assessing commercial viability, different retailers are likely to have different risk tolerances. Variation can be expected in both their accepted risk tolerance with respect to spot price exposure and their approach to analysing this risk (whether this is through regular detailed modelling or some other means). This further illustrates the point that ‘commercial viability’ is not a straightforward analytical exercise and that generator-retailers should not be unduly constrained in making this assessment.

4.8.2 Better define the term “observable market rates”

The Authority’s draft guidance states that generator-retailers should establish an economically meaningful portfolio of internal hedges and that “prices should be based on observable market rates for comparable risk management contracts, including baseload, peak and super-peak contracts (such as the standardised flexibility product)”.[91] In Meridian’s opinion the term “observable market rates” needs to be more formally and broadly defined. The definition should enable prices to be based on, for example, LCOE of generation assets (or other measures that would approximate the long-term price certainty that can be achieved using physical assets), PPA prices, OTC prices, the price of demand response options, and modelled long-term wholesale prices. Not all of these will be readily “observable” in the sense that they are publicly listed on an exchange or hedge disclosure platform. Therefore, a more suitable term may be “objectively justifiable market rates”. If the term is not more broadly defined then there is a high risk that integrated firms will need to adopt ASX prices and standardized super-peak prices for their notional internal hedges, limiting price smoothing to the duration of the forward curve for those products and resulting in increased volatility in retail pricing and higher retail prices in the near term (reflecting recent ASX prices).

4.8.3 Limit “buyers” to New Zealand wholesale participants

The draft guidance developed by the Authority states that a “gentailer is required to deal or offer to deal with buyers on substantially the same price and non-price terms and conditions (including quality, reliability and timeliness of service) as those made available (either expressly or implicitly) to the gentailer’s internal business units and other buyers.”[92] The term “buyer” is defined to mean:[93]

> *“a person who is –*
>
> - *specified as the buyer in a risk management contract with a gentailer; has otherwise obtained; or*
> - *is obtaining, a risk management contract from a gentailer; or*
> - *has indicated to a gentailer a desire to obtain risk management contracts from the gentailer*
>
> *and includes non-integrated retailers, non-integrated generators, or other gentailers but does not include a gentailer’s own internal business units.”*

This definition is extremely broad and means a buyer is any potential counterparty to a risk management contract with a gentailer, including international financial institutions. There may be a policy rationale for enabling New Zealand wholesale market participants to be buyers under the proposal as they need to manage spot price risks. However, there is no possible policy justification for granting non-participants the same rights. Doing so could require generator retailers to sell significant volumes to offshore speculators who would only be looking to sell back to New Zealand wholesale participants at a premium. This could cost New Zealand market participants and ultimately consumers. The risks associated with international

[91] Options Paper, Appendix B, para 15
[92] Options Paper, Appendix B, para 7
[93] Options Paper, Appendix B, Definitions

financial institutions becoming buyers under the proposal would also be greatly pronounced if arbitrage opportunities arise due to the proposal.

4.8.4 Explicitly enable notional hedge portfolios to grandparent in historic prices

To be workable, the drafting of the proposed principles and guidance should state explicitly that in establishing an economically meaningful portfolio of internal hedges, generator-retailers may grandparent in notional contract positions that in effect assume a retail segment had been transacting hedge agreements over several years in the past. This explicit acknowledgement is necessary to avoid the implication that a generator-retailer's notional hedge portfolio would begin on the first day that any proposal took effect and would therefore be based on current prices rather than a forward view of prices locked in at some point in the past.

If generator-retailers cannot grandparent in notional historic hedges this way, then immediate retail price rises would be necessary to comply with the no cross-subsidy principle.

4.8.5 Specify how generator-retailers should quantify "uncontracted risk management contract capacity"

The Authority's draft guidance states that a gentailer should "allocate its uncontracted risk management contract capacity on a non-discriminatory basis, such that the gentailer is unable to prioritise supplying its internal business units over buyers".[94] It is not clear to Meridian how this concept would be applied and interpreted in practice. As discussed in Appendix C, Meridian continuously tries to balance its portfolio to ensure adequate returns against a reasonable level of financial risk. Meridian's internal processes identify an optimal contract portfolio quarterly into the future that will best achieve this balance, and the contract book is constantly adjusted to achieve that optimal position. Real-time portfolio adjustments are also necessary to account for hydrology and factors such as planned and unplanned generation outages. Viewed through this lens there is often no 'spare' capacity waiting to be released into the market. This means that mandated hedge purchases by others would push a generator-retailer's portfolio to be over-subscribed and necessitate either:

(a) back-to-back hedge purchases by the generator-retailer to maintain its optimal contract portfolio; or

(b) shrinking of its retail market share to maintain the optimal contract portfolio.

It may be that the Authority intends that the volume of load consumed by a generator-retailer's mass market retail customers (i.e. the volume of notional internal hedges to cover that mass market retail position) should be the volume that is also made available to other buyers. However, it is far from clear whether that is the intention or if the Authority has something else in mind when it uses the term "uncontracted risk management contract capacity". Further guidance would aid implementation.

4.8.6 Specify how the proposal applies to new generation and flexibility investments

In Meridian's opinion, to make the proposal workable, the Authority would also need to specify how this concept of "uncontracted risk management capacity" applies to new generation and flexibility investments. If new investments are deemed to increase "uncontracted risk management capacity" and therefore increase the volumes that a gentailer must make available to buyers, then this would have a chilling effect on investment by gentailers.

[94] Options Paper, Appendix B, para 15

The Authority should consider explicitly excluding new investment after a specified date to avoid weakening investment incentives. In conversations with Authority staff it was suggested to Meridian that a retail segment could notionally be the party undertaking investments. It is unclear to us how this would work in practice and a clear exclusion in any Codified principles and guidance would be far preferable.

4.8.7 Ensure volume can be considered in credit and collateral arrangements with buyers

The draft guidance at paragraph 13 states that consideration should not be given to volume when applying proposed principles 1 and 3.[95] In Meridian's opinion, it is critical that volume can be considered in respect of principle 3 so that credit terms and collateral arrangements can reflect an objective assessment of the risk of trading with a buyer. If gentailers are prevented from considering volume for credit requirements they could not ask for additional bank guarantees, letters of credit, or similar from a buyer that wanted 1,000 GWh of cover compared to a buyer that only wanted 0.1 GWh of cover. Credit risks are directly related to volume and sellers must be able to ensure they are not exposed to undue credit risks in respect of higher volumes.

4.9 It is not clear how the Authority would monitor and enforce the proposed principles in the Code

As currently drafted, the proposed principles and guidance are vague, poorly defined, and open to a wide range of interpretations. We consider it will be extremely challenging for the Authority to monitor and enforce compliance with the proposed principles and equally challenging for generator-retailers to demonstrate their compliance.

If these principles are incorporated into the Code, both the Authority's Compliance Team and the Rulings Panel need to be able to enforce them. The proposal appears to be a break from the norm of drafting Code that the Rulings Panel can enforce. Rather than allege a breach, it seems likely the Authority would instead make assessments in future of whether the implementation by generator-retailers delivers the Authority's desired outcomes.[96] If not, the Authority has already identified potential steps 2 and 3 that could be taken to intervene further. However, the Authority has not said how or when it would make those assessments and decide if further steps are necessary. The criteria upon which those assessments would be made are also unclear at this stage.

Writing Code that is not able to be enforced but stating that the Authority will continue to intervene if it does not see certain undisclosed outcomes, sets up generator-retailers to fail and risks reputational harm to the companies involved and the industry in general. In Carl Hansen's expert report, he states:[97]

> *"In my view, the Authority's proposal will inevitably result in more intrusive interventions and needlessly harm the reputation of the retail electricity market."*

Reputational harm can be very costly. The Authority should mitigate this risk by specifying the conditions that would trigger further consideration of intervention as well as the process and decision-making criteria it would apply to assess the need to consider further interventions. This would increase certainty for industry and help generator-retailers to implement the

[95] Options Paper, Appendix B, para 13
[96] This assumption is supported by the Authority's response to a question on this issue, as set out at the link here.
[97] CSA, Section 1

proposal in a way that delivers the outcomes sought by the Authority and avoids further intervention and reputational harm.

4.10 The Authority needs to quantify the expected net benefits to consumers (if any)

The Authority's proposal inherently involves trade-offs. For example, the Options Paper notes that "any Level Playing Field measure runs some risk of a short-term increase in retail prices".[98] The Authority appears to reach a conclusion on this trade-off when it states the costs of non-discrimination principles are likely to be outweighed by benefits to consumers arising from greater competition, particularly over the longer-term.[99]

However, the Authority does not appear to have undertaken any quantification of costs and benefits to identify whether its proposal will result in a net benefit for consumers. We acknowledge the Authority will need to undertake a cost-benefit analysis at the next stage if it decides to proceed. However, some rough quantification of the expected net benefits (or otherwise) of each of the options assessed would have been helpful at this stage to provide guidance to both the Authority and submitters.

As noted by CSA, we would "hope to see a numerical cost-benefit assessment of the proposal rather a high-level qualitative assessment of the competition, reliability, efficiency and other effects of the proposal" in any next stage of this work.[100] This is critical considering:

(a) the high likelihood of retail price rises and consumer detriment in the near-term;

(b) the likely chilling of investment that would occur;

(c) the potential for significant disruption to the efficient free trading of risk;

(d) the potential distortions to competition including uneven impacts on generator-retailers and disadvantage to social retailers; and

(e) the scale of the expected wealth transfer to non-integrated retailers and smaller vertically integrated retailers and the need for caution when considering the claims of non-integrated firms due to their overwhelming commercial self-interest in regulatory intervention of this kind.

Longer-term competition benefits are by comparison uncertain, and the Authority would need to be certain the scale of any competition benefits would outweigh the costs to consumers and over what timeframe that benefit might be realised.

Carl Hansen has estimated the best-case outcome could be that it takes around *14 years* for enhanced competitive pressure to outweigh the effect of an initial increase in retail prices. This is under the highly optimistic assumption that competitive pressure is double the strength that it was between 2013 and 2018 with more conservative assumptions suggesting it could take twice as long before any net benefits are realised.[101]

The near-term cost impact of any regulatory developments should also be considered in the context of existing price rises for the distribution and transmission components of consumer bills for the regulatory control period that began 1 April 2025 and wider cost of living pressures.

[98] Options Paper, para 5.12
[99] Options Paper, para 6.51
[100] CSA, Section 2.5
[101] CSA, Appendix 2

5 Alternative approaches

Despite the fact that we consider the Authority has not clearly described and evidenced the problem it is seeking to address, we recognise the Authority may nevertheless continue down the path of progressing a ‘level playing field’ intervention. For this reason, we set out below two alternative options (one of which the Authority itself has identified) which we consider would better balance the Authority’s objective to promote retail and wholesale competition while avoiding unintended consequences.

5.1 Market making the standardised super peak product

As discussed in Section 3.1 above, the key issue identified in the Authority’s Risk Management Review was that it was unclear if pricing for OTC super peak hedge contracts was competitive as they trade at a substantial unquantified premium over ASX baseload prices adjusted for shape. In contrast, the Review confirmed that pricing for baseload and peak products was likely to be competitive.

While we consider that concerns over the pricing of super peak products are overstated (see the discussion in Section 3.1.2 above), this represents – in our view – the clearest potential ‘problem’ the Authority has identified. As such, it would make sense to focus any proposed intervention on this particular issue. Introducing market making obligations on the new standardised super peak product would be a more proportionate and targeted solution than the Authority’s current proposal.

The Options Paper notes that competitive pricing of baseload hedges is supported by ASX market making requirements.[102] Adopting similar obligations for the standardised super peak product could reasonably be expected to drive an increase in liquidity and would provide greater assurance around the competitiveness of super peak pricing. This would assist independent retailers in managing their wholesale market risk, support retail competition and improve price discovery.

We assume Meridian would face market making obligations under such a regime, with considerable associated cost (as is our experience in market making baseload ASX contracts). Nevertheless, the costs of such an intervention would be much more identifiable than is the case with the Authority’s level playing field proposal and risks of unintended consequences would be substantially reduced.

NERA have also concluded that market making of super peak products would be a preferable alternative to the Authority’s proposal (emphasis added):

> *“In order to ensure all parties have access to contracts, without unduly limiting the ability of gentailers to operate efficiently as well-hedged retailers, the EA could consider introducing a market-making obligation on super peak (and possibly peak) contracts.*
>
> *In practice, this would involve requiring gentailers to make a certain volume of contracts available each day, and with a maximum bid-ask spread. If the gentailer offered contracts at an artificially high price, then the limit on the bid-ask spread would create an opportunity for another party to arbitrage, by selling contracts to the gentailer at an artificially high price.*
>
> *Such a direct intervention would be **a more targeted approach appropriate to the problem of limited access to and high pricing of super peak contracts,***

[102] Options Paper, para 6.6(b)

without creating so many additional complications or unintended consequences that a functional unbundling would."

5.2 A negotiate-arbitrate regime

Option 3 in the Options Paper is the introduction of negotiate-arbitrate regulation. As the Authority notes, such a regime could involve imposing an obligation on generator-retailers to provide access to hedge contracts on fair, reasonable and non-discriminatory terms, backed by a binding arbitration process if commercial negotiations are unsuccessful. The Authority's assessment of this option identifies that it would be relatively low cost to implement and would preserve existing benefits of vertical integration. Identified limitations are that it would need to be well-designed, would rely on a qualified and independent arbitrator, and could create challenges around information asymmetries (although particular design approaches could overcome the latter issue).

In its criteria-based assessment in Table 5 of the Options Paper, the primary differences between negotiate-arbitrate regulation and the Authority's preferred option relate to costs and timing, with the Authority concluding:[103]

(a) Principles-based non-discrimination obligations would be "relatively quick to design and implement" while generator-retailers would face "some system costs to ensure compliance"; and

(b) Negotiate-arbitrate regulation "would take longer to implement" and "could be costly if used regularly".

Meridian disagrees with this assessment. As set out in Section 4.7 above, we consider that a principles-based non-discrimination obligation is, in fact, likely to take some time to implement effectively. This is both because of the complexities of the requirement for generator-retailers to establish a robust internal hedge portfolio (when one currently does not exist) and because we would expect there to be a 'learning period' as generator-retailers develop, deploy and adjust their respective approaches. Our view is that the costs faced by generator-retailers would be considerable as they work through the various complexities.

In contrast, while we acknowledge that a negotiate-arbitrate regime would require some upfront effort to develop, our view is that it would likely be less costly to implement in the long run. This is because initial arbitration decisions are likely to establish helpful precedents in the methodologies used to determine particular hedge prices which will provide guidance to subsequent commercial negotiations and likely lead to fewer arbitrations being required over time. At the same time, a negotiate-arbitrate regime would focus more clearly on the issue of competitive pricing of hedge contracts and would avoid the wider consequences and risk of unintended consequences that would arise from the virtual vertical separation that is inherent in the Authority's non-discrimination proposal. We recommend the Authority reconsider the relative merits of the negotiate-arbitrate option.

Carl Hansen has also identified the potential advantages of a negotiate-arbitrate approach and has proposed offering such an option as a 'safe harbour' within a non-discrimination obligation regime:[104]

[103] We acknowledge that the Authority has also identified that negotiate-arbitrate regulation "doesn't fully address issues with ITPs". However, under such an approach, independent retailers would be able to demonstrably access competitively priced hedge products – in such a situation, ITPs would be completely irrelevant.
[104] CSA, para 20

> *"Making the negotiate-arbitrate approach a safe harbour option will avoid compliance risks for gentailers, give [non-integrated retailers] greater certainty, and avoid the risk of short-term price rises for residential and commercial consumers."*

Mr Hansen also sets out some potential high-level aspects of the design of such a safe harbour and notes that such an approach could convert some of the cons of a negotiate-arbitrate approach into pros:[105]

> *"The Options paper states the arbitration approach could be costly if used regularly, depending on the decisions needed…However, having the approach available as an option means gentailers will consider those costs when choosing the negotiate-arbitrate safe harbour. Gentailers will only choose to incur additional costs if the additional benefits exceed those costs. As the interests of non-integrated parties is protected by their right to appoint arbitrators…offering the negotiate-arbitrate approach as a safe harbour option will be welfare improving."*

Meridian would similarly support a negotiate-arbitrate safe harbour, although we note the potential downside of this would be that the Authority has to effectively develop the detailed design of two different regimes.

6 Conclusions

Meridian supports competitive wholesale and retail markets. Our view is that New Zealand's electricity market has delivered and is continuing to deliver value for electricity consumers. We nevertheless recognise that the sector is in transition and that sources of energy we have previously relied upon (i.e. gas) are no longer available to the same extent. Both wholesale and hedge prices are reflecting that new reality.

The means to alleviate these current supply constraints is investment – investment in new generation capacity and in new flexibility. It is the sector's responsibility to deliver this investment. And it is the responsibility of policy and regulatory decision makers to ensure that the regulatory framework maintains strong incentives to invest. Anything that inhibits this will inevitably impact the future security and affordability of the electricity system. As noted by Carl Hansen:[106]

> "The best thing the Authority can do is encourage more supply to the market, to reduce wholesale electricity prices and end the price supercycle as soon as possible."

We share the concerns of our expert advisors that the Authority's proposal, if not designed and implemented carefully, risks impacting investment incentives and driving higher and more volatile retail prices. If the Authority continues with its proposal, we suggest careful consideration of these impacts. We also consider there would be merit in awaiting the findings of the current Government review to ensure any final proposal is consistent with the Government's broader policy direction.

Regardless of what is ultimately progressed, Meridian will do our utmost to make any changes work for the sector – and most importantly – for electricity consumers. We appreciate the Authority's willingness to engage with us on this proposal to date. We remain available to support the Authority at any point as it progresses its proposal through the next stage of development.

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[105] CSA, Section 5.2
[106] CSA, Section 1

Appendix A: Meridian responses to consultation questions

1.	**What are the benefits of vertical integration between generation and retail? Do you have any evidence to better specify and quantify these benefits? In particular, we are interested in benefits that would be realised by New Zealand's electricity consumers.**

As noted in Appendix B, we consider the benefits of vertical integration in managing wholesale market volatility have been well-canvassed in New Zealand and around the world. We would refer to the 2021 review of academic literature on this subject by Dr Richard Meade for ERANZ as a useful overview.[107]

Carl Hansen, in his expert report, discusses the ability of vertically integrated entities to offer price smoothing to consumers, materially improving their welfare. Refer, for example, to Section 3 of his report.

NERA's expert report also includes an extensive discussion on the benefits of vertical integration in Section 3, including the following benefits for electricity consumers specifically:

- Decreasing generators' incentives to exercise market power, which can result in a decrease in retail prices;
- Increasing the stability of retailers, which can assure stable retail prices; and
- Facilitating the construction of new generation which is essential to maintain the reliability of the grid and can lead to lower retail prices.

2. Do you agree with our description of the competition concerns that can arise from the combination of Gentailer vertical integration and market power? Why/why not? Do you have any evidence to better specify and quantify the competition risks of vertical integration?

Our views on the Authority's problem definition – including its description of competition concerns – are set out in Section 3 above. In summary, we consider:

- Many of the Authority's concerns are speculative;
- It is clear in a number of cases that the Authority has not been able to differentiate between genuine competition concerns and other factors (such as scarcity, fuel shortages, policy uncertainty, and investment lag);
- The Authority appears to have ignored – or at least has not sought to understand – potential alternative explanations for the high-level trends it has observed or evidence that is not consistent with its competition concerns; and
- The Authority has mischaracterised the findings of its own Risk Management Review.

Our view is this does not provide a sound basis on which to progress an intervention.

3. To what extent does vertical integration of smaller gentailers, such as Nova and Pulse, raise competition concerns? Should these smaller gentailers be subject to any proposed Level Playing Field measures?

[107] https://www.cognitus.co.nz/_files/ugd/022795_90a6a69bdaca4de9b752db7798bf2a2d.pdf

Our views on this are discussed in Section 4.6. In summary, we consider if the Authority implements its measures as proposed, smaller generator-retailers like Nova, Pulse and Lodestone would have a competitive advantage because they will not incur the same costs and inefficiencies and would be able to continue to offer longer-term price smoothing based on their generation investments and deliver the benefits of their chosen business model to end consumers. There is no justification for applying any proposed principles selectively to vertically integrated firms above a certain scale.
4. Are there other specific areas (other than access to hedges) where Gentailer market power and vertical integration are causing competition concerns?
Meridian disagrees with the assertion that gentailer market power and vertical integration are causing competition concerns. We emphasise the importance of the Authority robustly testing and understanding any suggestions of abuse of market power or competition concerns. As discussed in our submission and in the reports of our expert advisors, there are alternative explanations to the Authority's claims that observed trends in the retail market can be traced back to issues of market power. We also consider that the Authority's single-minded focus on identifying competition concerns have led it to ignore other critical market issues, notably the decline of New Zealand's gas sector.
5. Do you agree with our preliminary view that the evidence indicates there may be good reasons to introduce a proportionate Level Playing Field measure to address the competition risks in relation to hedging/firming? Why/why not?
We disagree. As discussed in our submission, Meridian's view is that the Authority's problem definition is vague, lacks robust evidence and is, at times, misleading. It does not establish a convincing basis for subsequent intervention. We consider that a level playing field already exists between generator-retailers and independent retailers and generators. Rather than a level playing field, the Authority's proposal seems to be aimed at achieving level outcomes. The Authority should not prefer one business model over another or seek to advantage one type of participant over another. It will only result in greater costs for consumers if New Zealand subsidises or supports inefficient business models.
6. Have we focused on the right Level Playing Field options? Are there other options that we should add or remove to the list in paragraph 4.1?
As discussed in Section 5, our view is that mandating market making of super peak products or a negotiate-arbitrate regime would represent better targeted interventions and would likely have lower costs and lower risk of unintended consequences than the Authority's proposal.
7. Are there any other important factors we should consider when identifying options (see paragraphs 4.2 to 4.5)?
We consider the identification of options should be clearly focussed on those areas where there is evidence of a problem. In this case, based on the Authority's Risk Management Review, this suggests an intervention focussed on the market for super peak products.
8. Are there other key features, pros or cons we should consider in our description of the four Level Playing Field options?

As discussed throughout our submission, we consider the key risks – or cons – of non-discrimination obligations are the chilling of investment incentives and higher and more volatile retail prices. We also consider that the description of non-discrimination obligations as being "relatively low cost" and "relatively quick to design and implement" is overly optimistic. In our view, this approach will be highly complex to implement which will drive high compliance costs, risk unintended consequences, and may be less likely to achieve the Authority's desired outcomes. With all generator-retailers subject to these high compliance costs, these costs are ultimately likely to be passed through to consumers.
9. Have we identified the right criteria for assessing Level Playing Field options (Figure 6)? Is there anything we should add or remove?
We suggest adding the criteria 'near-term impact on retail prices/affordability'.
10. Do you agree with our application of the assessment criteria (Table 5)? Are changes needed to the colour coding or reasoning?
With respect to Option 2: • We consider the 'generation entry/build' criteria should be rated 'negative'. As described by NERA, there is a strong risk the proposal will have a negative impact on investment incentives, including incentives to invest in flexible capacity; • We consider the 'investment in new flexibility' criteria should be rated 'negative' for the same reasons described above; • We consider the 'other efficiencies' criteria should be rated 'very negative' given this option will effectively virtually disaggregate generator-retailers over time, eroding the well-established efficiency benefits of vertical integration; • We consider the 'costs and timing' criteria should be rated 'weak negative' given this option is complex and will require significant effort and judgement to be applied by generator-retailers to implement. Transaction costs are ultimately likely to flow through to consumers. With respect to Option 3: • We consider the 'costs and timing' criteria should be rated 'neutral'. As discussed in our submission, our view is that a negotiate-arbitrate regime would be less costly to implement in the long run as initial arbitration decisions are likely to establish helpful precedents in the methodologies used to determine particular hedge prices which will provide guidance to subsequent commercial negotiations and lead to fewer arbitrations being required over time. Our lack of comment on other options or criteria should not be taken as an endorsement of the Authority's ratings – we are simply focussing on the critical factors and options that we have identified and discussed in our submission.
11. Are there any other material benefits or risks that should be considered (but are currently not) in our assessment of options?
As per our response to Question 9, we suggest adding the criteria 'near-term impact on retail prices/affordability'.

12. Do you agree with our selection of non-discrimination obligations as our preferred Level Playing Field measure? Why/why not?
As discussed in our submission, mandated market making of super peak contracts and a negotiate-arbitrate regime would both be preferred interventions to the Authority's proposal. The reasons for this are discussed extensively in our submission and in the accompanying expert reports from Carl Hansen and NERA. Regardless of which option is ultimately progressed, Meridian will do our utmost to make any changes work for the sector – and most importantly – for electricity consumers.
13. What are your views on our proposed roadmap for the implementation of non-discrimination obligations?
We consider that the ambiguity of the proposed principles-based approach to non-discrimination obligations will create a high risk that the Authority will need to progress to Step 2 in its roadmap. This will create a slippery slope of intervention. As noted by Carl Hansen, the proposal risks further harming the reputation of the electricity market if the Authority assesses compliance breaches, introduces prescriptive rules, creating more compliance breaches until gentailers learn what the Authority expects, and on and on. Reputational harm could be very costly for the wider industry.
14. Which products should any non-discrimination obligations apply to? Should all hedge contracts be captured, or should the rules be focused on super-peak hedges only? Are there other interactions between Gentailers and their competitors which would benefit from non-discrimination rules?
As discussed in our submission, it is clear from the Risk Management Review findings that the only concern the Authority has identified is in relation to the pricing of super peak products. However, the Authority's proposal as currently written will capture all hedge contracts offered by generator-retailers, including those the Authority has confirmed are likely to be trading competitively. In our view, this significant broadening of the scope of the intervention is inconsistent with a robust regulatory development process and heightens the risk of unintended consequences without any underlying justification. If the Authority is confident that the analysis in its Risk Management Review remains robust, then a more proportionate and reasonable response would be to focus its intervention on ensuring a competitive and liquid market for super peak products.
15. Do you have any feedback on the indicative draft non-discrimination principles (and guidance) set out in Appendix B? Without limiting your feedback, we would be particularly interested in your views on the following questions: **a. Have we got the level of detail/prescription right? For example, do you consider that the principles and guidance will lead to economically meaningful Gentailer ITPs being put in place? What would be the costs and benefits of instead applying a more prescriptive ITP methodology?** **b. How far should the allowance in the principles for different treatment where there is a "cost-based, objectively justifiable reason" extend? Do you agree with the guidance that this allowance should not be extended to volume (at paragraph 13 of Appendix B)?**
As discussed in Section 4.8 of our submission, if the Authority intends to develop this proposal further, several changes are necessary to improve its workability. At a minimum, these include:

- Clearly specify that the standalone commercial viability of a retail segment should be assessed over several years;
- Better define the term "observable market rates";
- Limit "buyers" to New Zealand wholesale participants;
- Explicitly enable notional hedge portfolios to grandparent in historic prices;
- Specify how generator-retailers should quantify "uncontracted risk management contract capacity";
- Specify how the proposal applies to new generation and flexibility investments; and
- Ensure volume can be considered in credit and collateral arrangements with buyers (i.e. we disagree that the allowance for a "cost-based, objectively justifiable reason" should not be extended to volume).

16. Do you agree that escalation options are needed if principles-based non-discrimination obligations are implemented initially? Why/why not?

Refer to our response to Question 13.

17. Are prescribed non-discrimination requirements and mandatory trading of Gentailer hedges via a common platform suitable escalations given the liquidity, competitive pricing and even-handedness outcomes we are seeking? Why/why not? What alternatives would you suggest (if any)?

We consider these escalations are not suitable given the available evidence on the nature and scope of the problem i.e. it is unclear whether super peak products are being competitively priced. We consider more proportionate and targeted options would be mandated market making of a super peak product or a negotiate-arbitrate regime. These options are discussed further in our submission and in the reports from our expert advisors.

18. What costs and benefits are likely to be involved in setting more prescriptive regulatory accounting rules which detail how ITPs should be calculated? What would be appropriate triggers for introducing more prescriptive requirements for ITPs?

We consider it would be challenging and costly to adopt a more prescriptive approach. However, as discussed in our submission, we consider the proposed principles-based approach is likely to see generator-retailers choosing to implement the proposal in different ways, resulting in a more chaotic implementation. It is hard to see how this will benefit consumers.

As stated by Carl Hansen: "Unless the Authority offers a 'safe harbour' option…it may be better for the Authority to introduce prescriptive non-discrimination obligations. At least that way the Authority would have to confront the realities of what they are requiring of gentailers".

19. Do you have any views on how the non-discrimination requirements should best be implemented to ensure that Gentailers are no longer able to allocate uncontracted hedge volumes to their own retail function in preference to third parties? What are the key issues and trade-offs?

Our understanding is that the Authority is seeking to implement this requirement through the principle that "a gentailer must not discriminate against buyers in favour of its own internal business units…without a cost-based, objectively justifiable reason” and the associated guidance that a generator-retailer should “allocate its uncontracted risk management contract capacity on a non-discriminatory basis, such that the gentailer is unable to prioritise supplying its internal business units over buyers”.

Meridian’s view is that, if such a requirement is to be effective, the Authority needs to provide greater guidance on how “uncontracted hedge volumes” should be calculated. Hedge portfolios are complex and dynamic, and different generator-retailers may take substantially different views on how this requirement should be interpreted. Further changes to improve the workability of the Authority’s proposal are summarised in our response to Question 15 above and in Section 4.8 of our submission

20. Do you have any views on the triggers for implementing the stronger regulation proposed in our roadmap?

As noted in our submission, our view is that the standalone commercial viability of a retail segment should be assessed over several years. This would allow any judgement on this matter to reflect the strength of a business’ balance sheet to ride through a commodity cycle and be profitable over the long run.

At this stage, we do not have views on the specific triggers which should be used for progressing to stronger regulation. However, as per the above, we consider the timeframes for assessing those triggers need to be sufficient to allow for long run commercial viability to be assessed.

If the Authority does proceed with its proposal, it needs to be clear at the outset what it considers the triggers to be and how it will make the decision to intervene further. See Section 4.9 of our submission for further discussion of implementation and enforcement challenges.

21. Does our proposed approach to implementing non-discrimination obligations (as set out in the roadmap in Figure 7) sufficiently address the underlying issue that originally led to MDAG recommending virtual disaggregation?

The Authority appears to be referring here to the issue of a future concentration in the supply of flexibility services. As noted in our submission, MDAG recommended that a ‘virtual disaggregation’ option be developed to ‘put in the drawer’ ready for use if other measures are not effective and in the event of thermal retirements and concentration of flexibility. Meridian’s view is that it is currently premature to pursue virtual disaggregation. We agree that the electricity system will need additional flexibility going forward. Our own analysis indicates 200 MW of additional flexibility will be needed each year for the next 25 years. In this context, it is critical that there are clear and stable investment incentives to develop additional flexibility.

Meridian’s view is the Authority’s proposal:

- Is effectively implementing virtual disaggregation now (although this is *vertical* disaggregation rather than the horizonal disaggregation of flexible generation or storage considered by MDAG). As generator-retailers will be unable to prioritise sales to their own retail business units, the inevitable consequence over the long run is that generator-retailer’s generation and retail units will become disaggregated, increasing costs and inefficiencies, and significantly impacting the benefits that arise from vertical integration and the price-smoothing services enjoyed by consumers; and
- Will negatively impact incentives to invest in flexibility. As set out by NERA, if a gentailer is not able to fully use its flexible generation to offset risk for its retail arm, and does not capture the full value of the insurance it provides because it is forced to sell at below market value

to other firms, then this takes away a substantial portion of the value of building it, and hence reduces the incentive to build it. Similarly, to the extent the proposal increases retail price volatility, gentailer earnings will be more volatile and financing to support investment may be higher cost as a result.

Rather than addressing the underlying issue identified by MDAG, our view is the Authority's proposal will make this issue worse by chilling investment in flexible generation while imposing additional and unnecessary costs on consumers.

22. Do you have any views on whether virtual disaggregation provides a useful response to the competition risks we have identified (relative to the proposed roadmap) and, if it does, how it should be best applied?

As above, MDAG's virtual disaggregation option was developed to address a completely different concern to the risks now identified by the Authority.

Appendix B: Benefits of vertical integration in the New Zealand electricity sector

Wholesale electricity markets are recognized as one of the more volatile types of commodity markets in the world. While MDAG concluded that the New Zealand market is considerably less volatile than other international markets, significant volatility is still expected given the system's need to instantaneously balance supply and demand, limited capacity for storage, and a reliance on unpredictable and uncontrollable weather.[108]

The advantages of adopting a vertically integrated structure to manage this volatility have been well canvassed in New Zealand and around the world. A 2021 review of academic literature on this subject by Dr Richard Meade for the Electricity Retailers Association of New Zealand (ERANZ) found that:[109]

(a) vertical integration – where it naturally arises – is superior to vertical separation in managing wholesale price risks, supporting investment, reducing incentives for the exercise of market power, and providing better outcomes for consumers;

(b) while vertical integration can give rise to anticompetitive opportunities such as foreclosure (refusing to supply rivals), integration is not always associated with such activities, especially in electricity systems which have design and regulatory features which reduce foreclosure risk;

(c) even when foreclosure incentives exist, the benefits of integration are sufficient to result in net consumer benefits; and

(d) where naturally-occurring vertically integrated firms are forcibly separated, there is solid evidence from a variety of sectors around the world that this harms consumers.

NERA's expert report similarly concludes that vertical integration delivers benefits for both market participants and for consumers:[110]

> *"…by reducing transaction costs, providing firms with flexible risk management through an internal hedge, and assuring that their risk management needs are met, vertical integration can be a more efficient way for electricity market participants to manage wholesale electricity market risk."*

and:[111]

> *"In electricity markets specifically, vertical integration can provide value to the consumers of electricity in several ways, including by:*
>
> - *Decreasing generators' incentives to exercise market power, which can result in a decrease in retail prices,*
> - *Increasing the stability of retailers, which can assure stable retail prices, and;*

[108] Price discovery in a renewables-based electricity system – Final recommendations paper, MDAG, December 2023, link, pp37-39
[109] https://www.cognitus.co.nz/_files/ugd/022795_90a6a69bdaca4de9b752db7798bf2a2d.pdf
[110] NERA, Section 3.3
[111] NERA, Section 3.4

- *Facilitating the construction of new generation which is essential to maintain the reliability of the grid and can lead to lower retail prices."*

The Authority itself acknowledges seven benefits of vertical integration in the Options Paper: risk management, reduced financing costs, reduced transaction costs, coordination of investment, economies of scope, elimination of double marginalisation, and financially robust.

The Authority also acknowledges the claim of independent retailers that the benefits of vertical integration are largely financial or risk management-based rather than relating to productive efficiencies.[112] This apparent dismissal of financial and risk management benefits significantly underemphasises their importance. NERA refers to the independent retailers' claim and notes it would be:[113]

> *"…incorrect to downplay any efficiencies from vertical integration in electricity markets on the basis they are financial or risk management based, given these efficiencies relate to one of the core functions of electricity markets".*

NERA also notes that the 'productive efficiencies' referred to by independent retailers are likely a very small part of the cost of retail electricity sales and should therefore be of lesser concern than efficiencies related to risk management.

The merits of vertical integration have also been well considered in a New Zealand regulatory context:

(a) The 2009 Ministerial Review concluded that vertical integration was beneficial to consumers and highlighted the criticality of a liquid contracts market in mitigating the downsides of vertical integration;

(b) The previous Government's Electricity Price Review found that vertical integration can provide significant benefit to consumers while forced separation would be "disruptive, undermine investor confidence and stall or delay the huge amount of generation investment needed to move to a low-carbon economy";[114]

(c) MDAG concluded from its comprehensive assessment of the wholesale market that ownership separation between generation and retail activities should not be adopted as a backstop tool;[115] and

(d) The Electricity Authority rejected vertical separation in its 2023 Decision Paper following its review of competition in the wholesale market.[116]

It is clear that there is a wealth of evidence – in New Zealand and globally – that vertical integration is an efficient business model that delivers significant consumer benefits while, in contrast, vertical separation would work to the detriment of consumers.

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[112] Options Paper, para 3.18
[113] NERA, Section 3.1
[114] Electricity Price Review: Final Report, link, p41
[115] Price discovery in a renewables-based electricity system – Final recommendations paper, MDAG, December 2023, link, p166
[116] Promoting competition in the wholesale electricity market in the transition toward a renewables-based electricity system – Decision Paper, Electricity Authority, May 2023, link, para 4.11

Appendix C: Meridian’s approach to portfolio management

With the formal reset of market arrangements that occurred in 2011 and further encouraged by market listing in 2013, Meridian has now spent the last 14 years efficiently managing and investing in our existing hydro and wind assets, creating new generation and new flexibility assets, securing a large pipeline of new generation and flexibility options, and building up a large, diverse retail and customer base including a number of formalised demand-response agreements.

By their nature some of these actions are relatively short-lived, some medium-term, and many, especially when linked to assets, require a multi-decade perspective and commitment. For all of these commercial activities, financial exposure is only ever exposed in the fullness of time, when price and volume become the ultimate arbiter of whether any particular decision in hindsight was a good idea or not. That is the nature of the significant investment risk that Meridian and other market participants face.

These activities cover generation, contracting, and retailing actions. The nature of the New Zealand half-hourly wholesale market means that generation and contract income can help to offset load and contract purchase costs, to some degree, especially when in a similar location and of a similar scale. As imbalances between sales and purchases occur and as underlying spot prices rise and ebb, significant operational portfolio cashflow risks can still remain.

This can occur in response to anything that materially impacts on supply or demand, from hydrology and storage lakes, new demand, retrenchment of demand, transmission constraints and plant failures, through to the impacts of renewable intermittency. This is a measurable risk, for an assumed state of the market, and Meridian takes great care in balancing available energy and capacity against contract and other load commitments.

Broadly speaking, Meridian does this in a way that continuously tries to balance and ensure adequate returns against a reasonable level of financial risk. Viewed through this lens there is no ‘spare’ capacity waiting to be released into the market. At least over a 12-24 month horizon, we maintain a fully committed ‘book’. This position is adjusted as hydrology and other key uncertainties unfold and deviations from this optimised position will create earnings losses, additional portfolio financial risks, or both. A version of what these risks might mean can be seen recently, when Mercury and Meridian both posted significantly negative profit results for the final six months of 2024.

All participants in the market must manage these risks to varying degrees and all will have a different approach on how they do that and on what they think works best for them and their owners. There is no definitively correct approach. Somewhat conventionally, Meridian manages short and medium-term portfolio risks along with some amount of longer-term investment risk by maintaining a vertically integrated business. That is to say, we are a business that balances quantities of generation income, customer sales incomes, and market purchase obligations from half-hour to half-hour. There are no internal contracts that achieve this: under current settings these would be entirely redundant and impose unnecessary transaction costs. Instead, we rely on offsetting and measurable positive and negative cashflows.

As outlined above, in Meridian’s case this position has been built up over a number of years and includes a range of agreements with other parties at different prices, scales, shapes and durations. At the point of agreement, both parties were happy with the terms and conditions by demonstration. Whether parties remain happy is moot – these are the risks that both parties engage with.

Meridian balances financial returns against an appropriate level of investment, portfolio and physical risks, all while delivering secure, renewable energy and flexibility to the market with our customers at the forefront of all of our decisions. Over the last 14 years we have invested at our own risk, managed our own contract and retail positions, bought, sold, created short-term and long-term arrangements – all to create the business that we have today. There is nothing wrong with this approach, and by the very nature of our market, any party including independent retailers or new entrant generators could similarly take this approach should they so choose. Indeed, Lodestone Energy has recently taken such a step.[117] As reflects the realities of the power system and the energy needs of New Zealand, this requires long-term commitment, investment, and balancing risk and reward to be at the centre of their – and our – decisions.

[117] https://lodestoneenergy.co.nz/lodestone-becomes-an-energy-retailer/

Appendix D: Expert report from Carl Hansen (Capital Strategic Advisors)

Appendix E: Expert report from NERA

CAPITAL STRATEGIC ADVISORS

Report prepared for

Meridian Energy Limited

Review of the Electricity Authority's Level Playing Field options paper

Carl Hansen

6 May 2025

About Capital Strategic Advisors (CSA)

Based in the capital city of New Zealand, CSA provides strategic policy advice to government and private sector clients. CSA has expertise in regulatory and tax policy, market and organisational design, institutional economics, pricing theory and practice, competition and infrastructure issues, and the implications of innovation and technology change for regulatory design, productivity, and economic growth.

Carl Hansen is based in Wellington, New Zealand. He is currently Strategic advisor to Meridian's board and management and is a member of the Reserve Bank's monetary policy committee. He was the chief executive of the New Zealand Electricity Authority for eight years and a member of the National Infrastructure Advisory Board. Carl has strategic and practical experience with formulating public policy, and has held numerous advisory, executive and chairing roles. Carl spent almost a decade with market services company M-co, originally as chief economist and then as chief executive. He also worked for the Law and Economics Consulting Group, the New Zealand Treasury, the New Zealand Business Roundtable and the Reserve Bank of New Zealand.

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Contents

Key points

1. The Authority's problem definition, proposal and alternatives are presented in a paper entitled *Level Playing Field measures: Options paper* (Options paper).

The Authority's problem definition needs further thought

2. The Options paper compares 'apples and oranges' when it compares prices for ASX contracts (less than 4 years) with generation costs estimated over 25^{+} years.
3. The paper does not mention that real retail prices have declined since December 2020, which does not correlate well with its concerns about stalled competition.
4. The paper places significant weight on the lack of definitive empirical results about prices for super-peak hedge products. However, the Authority's risk management modelling implies those prices would have minimal impact on the competitiveness of non-integrated retailers (NIRs).
5. Crucially, the paper ignores the reality that vertical integration enables control of arbitrage risk. The proposed non-discrimination rules will need to address this issue if gentailers are to sell long-term contracts to NIRs at historical prices. On the other hand, if the rules allow sale of long-term contracts at forward-looking prices, then retail prices may rise significantly (see points 10-13 below).
6. The paper seems to assume incumbent NIRs want to buy long-term hedge contracts at forward-looking prices. However, this would expose them to the risk of new entrants outcompeting them if hedge prices decline for a sustained period. As retailing is a thin-margin business, they would need to hold significant cash reserves or have access to additional debt and equity to ride through the price cycle.

Market outcomes reflect adverse supply shocks and market asymmetries, not market power

7. There are valid alternatives to the claim that market outcomes reflect gentailer market power.
8. Recent retail market outcomes reflect several asymmetries:
    a. Since 2018, the wholesale market has suffered many adverse supply shocks, and they have been longer lasting than anticipated. The wholesale market is experiencing a *price supercycle*.
    b. There is a fundamental asymmetry between hedge and retail markets. Prices for hedge products must align with expected spot prices (and with each other) to avoid arbitrage, whereas prices for retail supply contracts do not have to align.
    c. Incumbents with long-lived generation assets are typically better placed to ride through price supercycles than competitors with short-lived assets and thin margins.
9. A prolonged period of price smoothing can be a competitive equilibrium because it serves the interests of retail consumers. It could occur even if the electricity market had 20 incumbent gentailers with 5% market share each, for example.

The Authority's proposal carries significant price risks for households

10. The Options paper says there is a disconnect between internal transfer prices and retail prices but then ignores the retail price implications of fixing that disconnect. This is surprising, as hedge prices have increased about 90% in real terms since mid-2018 yet residential retail prices have declined 6.7% in real terms.
11. The non-discrimination obligations require gentailers to set their internal transfer prices based on market prices, and the no cross-subsidy obligation requires them to set their retail prices based on those internal transfer prices. These obligations will increase retail prices. Electricity bills for households could increase by 21-26%, or $460-570 per year.
12. If hedge prices remain elevated for another year and then decline steadily to neutral, the average household could end up paying $818 more in electricity bills during that period. It could easily take another 15 years for households to be better off.
13. These considerations suggest the proposal increases the risk of a future government introducing price caps, which tend to harm NIRs. They become insolvent when wholesale prices rise faster than regulators allow retail price rises.

The Authority's proposal has significant implementation and compliance problems

14. The Options paper flips between two non-discrimination benchmarks. Paragraph 4.15 requires gentailers treat themselves substantially the same as they currently treat non-integrated competitors, whereas paragraph 4.16 requires the converse: gentailers must treat others the same as they currently treat themselves. The retail price risks with 4.15 were discussed above.
15. The problem with 4.16 is that hedge contracts are easily arbitraged. If gentailers must base their offers on a subjective assessment of prices implicitly charged to their own retail division, then contract buyers can arbitrage the price differences across gentailers. This pricing approach is infeasible. Indeed, so is any approach that systematically deviates from competitive pricing of hedges.
16. The paper understates the implications of its proposal for gentailer compliance costs and uncertainty. This is reflected in its own evaluation of the principles-based approach, which states that it would leave room for interpretation, may make it difficult to identify discrimination, and monitoring and enforcement could be challenging.
17. The proposal risks further harming the reputation of the electricity market if the Authority assesses compliance breaches, introduces prescriptive rules, creating more compliance breaches until gentailers learn what the Authority expects, and on and on. Reputational harm could be very costly for the wider industry.
18. Unless the Authority offers a 'safe harbour' option, in my view it may be better for the Authority to introduce prescriptive non-discrimination obligations. At least that way the Authority would have to confront the realities of what they are requiring of gentailers.

The Authority should allow the negotiate-arbitrate option as a safe harbour

19. If the Authority decides to proceed with its non-discrimination proposal, a safe harbour option is warranted to reduce uncertainty and costs for all parties.

20. Making the negotiate-arbitrate approach a safe harbour option will avoid compliance risks for gentailers, give NIRs greater certainty, and avoid the risk of short-term price rises for residential and commercial consumers.

21. If any gentailer elects the negotiate-arbitrate safe harbour, the Authority would gain valuable information about its pros and cons before it considered more intrusive options, such as step 2 in the Options paper. NIRs would be better placed to offer their views on the pros and cons, based on actual experience rather than hypotheticals. Arbitrators would also have valuable insights.

Concluding comments

22. I have long advocated for reducing barriers to entry for NIRs and viewed their involvement in the market as a contest between business models. However, it was never a case of viewing one model as better than the other, or that the absence of one signalled the market wasn't working. It was up to the market to decide whether one model wins, or they coexist.

1 Introduction

The Energy Competition Task Force (Task Force) recently announced that non-discrimination measures are its preferred option to level the playing field between gentailers and independent participants in the electricity market.[1] The proposal and alternatives are presented in a paper released by the Electricity Authority entitled *Level Playing Field measures: Options paper* (Options paper).

The analysis and proposal in the Options paper relies on analysis and evidence presented in two previous reviews: a companion paper providing an update on its review of risk management options for electricity retailers (Update paper), and its review of internal transfer pricing and retail gross margins (ITP/RGM paper).

Meridian Energy requested I prepare an independent assessment of the Authority's Options paper. I agreed to do so because it seemed odd the Authority was proposing a wide-ranging intervention to address a narrow hedge market issue in the Update paper. Further, the Update paper makes it clear the Authority does not have robust empirical evidence the narrow issue is a problem requiring regulatory intervention.

I am very concerned the Task Force has mis-diagnosed the problem confronting non-integrated retailers (NIRs) and does not appear to have fully considered important factors, such as asymmetries between the hedge and retail markets and retail pricing in the face of repeated adverse supply shocks, that were thought more temporary than has turned out to be the case. In my view, this is leading the Authority to propose options that are likely to materially increase prices for households and businesses. It could also harm non-integrated retailers in the long run. Both are unnecessary.

I am concerned about the workability of the non-discrimination rules, which arises because the proposed rules are in the form of high-level principles, allowing the Authority to ignore important details. I am particularly concerned that it does not appear to have considered the arbitrage implications of its proposal, and it has given scant attention to implications for retail prices.

In my view, the Authority's proposal will inevitably result in more intrusive interventions and needlessly harm the reputation of the retail electricity market. If the Authority proceeds with its proposal, it would be wise to introduce 'safe harbour' provisions.

I am sympathetic to the plight of NIRs. They have been caught by a supercycle that no one anticipated, for which they are poorly placed to manage. The best thing the Authority can do is encourage more supply to the market, to reduce wholesale electricity prices and end the price supercycle as soon as possible.

[1] https://www.ea.govt.nz/news/press-release/energy-competition-task-force-looks-to-level-the-playing-field-between-the-gentailers-and-independent-generators-and-retailers/

2 Concerns with the problem definition and proposal

The Task Force is over-focusing on hypothetical competition concerns and short-run risk management. In my view the underlying issue is that NIRs have traditionally been more focused on the short-run and therefore have poor long-run price-smoothing capabilities relative to incumbent generator-retailers (*gentailers*).[2] This is a key drawback of their business model, as long periods of price-smoothing can occur in competitive markets and are likely to be welfare-maximising. These considerations are presented in section 3.

This section focuses on concerns I have about the analysis in the Options paper. Sections 2.1 - 2.4 discuss concerns with the problem definition, and section 2.5 discusses concerns with the logic and workability of the proposal.

2.1 Concerns about barriers to generation competition are unconvincing

The Options paper states that gentailers have the opportunity and incentive to restrict generation competition because of their control of the flexible generation base, and therefore of the firming/hedging input their competitors need, at least in the short to medium term (3.51a).[3]

The Options paper does not offer any rigorous evidence regarding *opportunities* or *incentives*. Rather, it infers there may be barriers to entry and/or expansion in generation because there has been limited growth of competing generators (3.15). It also discusses the persistence of price vs cost margins (see next subsection).

The casual approach to this topic is surprising, for the reasons discussed below.

Flat electricity demand

Firstly, it is well-known that electricity demand has been largely flat since 1990, so minimal new generation has been needed other than to replace plants that have reached their end of life. Further, uncertainty around the future of NZAS since 2012, and even earlier, likely chilled generation investment.[4] In these circumstances, why would there be significant growth of competing generators?

Non-gentailers account for 51% of committed investment

Secondly, now that demand is expected to grow rapidly, the Authority's investment pipeline shows that 51% of investments committed for the period to December 2028 were driven by parties other than "NZ integrated", that is, other than gentailers. This is highlighted in Figure 1 below. For actively pursued projects, the gentailer share is only 23%.[5]

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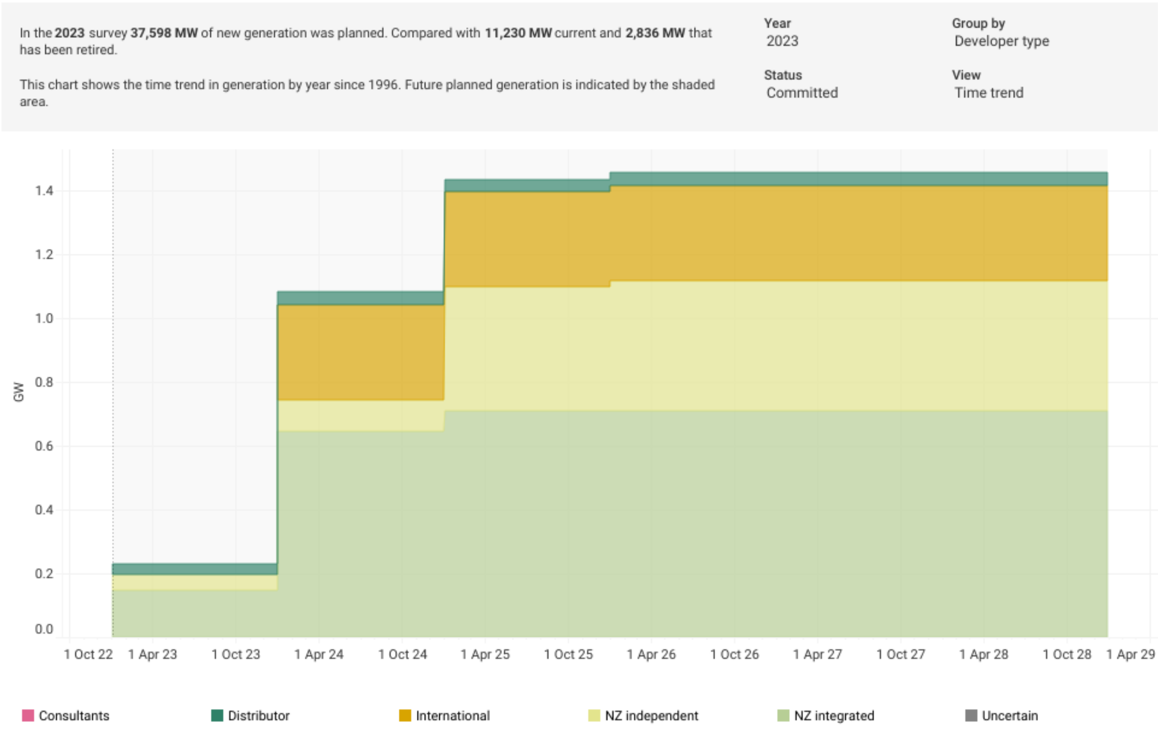
[2] An *incumbent* in this note is any market participant operating in the market prior to mid-2018, as wholesale market prices have remained elevated since then. All major gentailers in the market are incumbents, as are many NIRs. Participants who entered the market after mid-2018 are called *new entrants* in this note.

[3] Numbers in parentheses refer to paragraph numbers in the Options paper.

[4] https://www.treasury.govt.nz/sites/default/files/2013-09/nzas-2392548.pdf.

[5] https://public.tableau.com/app/profile/electricity.authority/viz/Investmentpipeline/Investmentpipeline

Figure 1: Committed generation investments by type of developer, gigawatt capacity



Further, there are over 100 separate generation companies operating in New Zealand, most of whom are connected to distribution networks.

The large proportion of investments made by non-gentailers, and the large number of generators, suggests minimal barriers to entry or expansion. Rather, the issue has been low growth in electricity demand.

Public policy has likely undermined the business case for thermal investment

The investment pipeline shows that 67% of committed investments were for intermittent generation. The remainder comprised 22% geothermal, 9% batteries, and 2% firming generation (hydro and thermal).

Although there are resource and environmental limits to adding geothermal and hydro generation, the only limit to building thermal generation is its commercial viability, which is driven primarily by availability and cost of fuel and public policies affecting dispatch of thermal generation over the expected life of the plant.

Those policies include the NZ Battery project and the offshore exploration ban, which raised sovereign risk and had a chilling effect on investment in maintaining gas field output, the effects of which are now evident. It appears those policies significantly weakened the commercial case for investment in thermal peaker plants.

Gentailers are often net buyers on the spot and hedge market

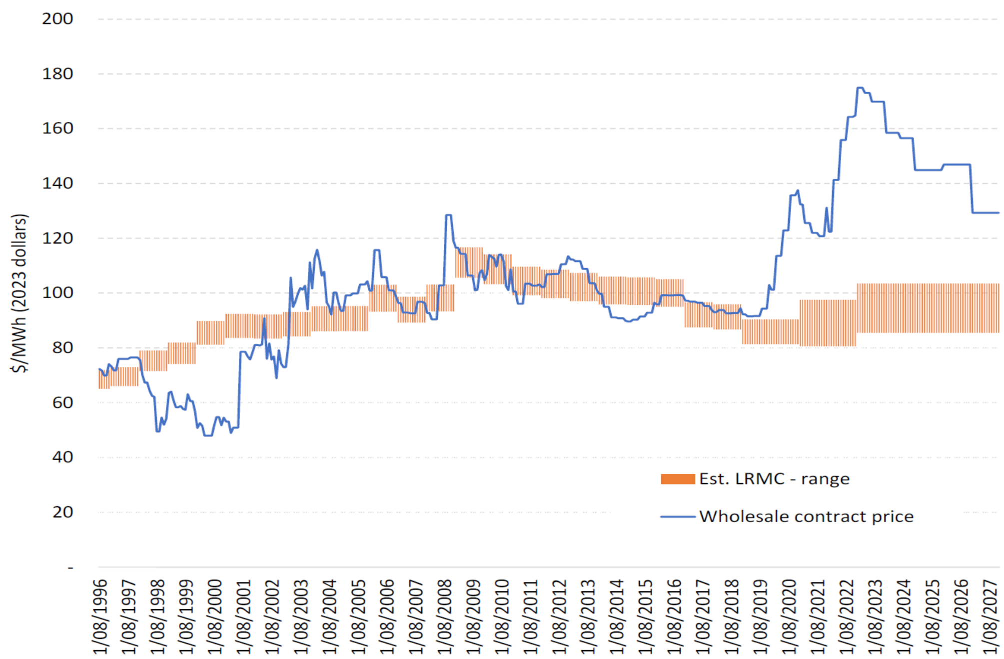
Each gentailer has incentives to compete strongly in the spot and hedge markets. When the hydro lakes are lower than average, the hydro gentailers become net buyers on the spot and hedge market, so their incentive is to minimise spot and hedge prices. When the hydro lakes are higher than average, the non-hydro gentailers become net buyers, and seek to minimise prices.

The volatile dynamics of the various fuel sources – hydro, wind, solar and even gas and coal – makes for an unpredictable operating environment for generators. However, each gentailer is highly incentivised to make timely investments as soon as it believes future market prices will justify the costs. Each knows that if it dithers, a competitor may jump in with an investment that crowds them out until market demand grows sufficiently to justify another investment. We are currently witnessing this dynamic, with gentailers racing to invest in solar, wind and batteries.

Price vs cost comparisons need to be interpreted with care

The Options paper notes there is a large and ongoing gap between ASX hedge prices at Otahuhu and the long run marginal cost (LRMC) of new baseload generation (3.41). Figure 4 in the Options paper is repeated below for easy reference.

Figure 2: Repeat of Figure 4 from the Options paper



The chart shows hedge prices peaking in 2023, at about 75% higher than the upper estimate of cost, declining to about 30% by August 2027. However, these price-cost margins must be interpreted carefully because the hedge prices are only for 2-4 years ahead, whereas the LRMC estimates are the average cost of energy over a plant's entire life.[6] For example, solar and wind plants last 25-35 years, and many baseload plants last far longer. In essence, the chart is comparing 'apples and oranges.'

A numerical example is provided in Appendix 1 to illustrate the care needed. It assumes the cost estimates are based on a 7% cost of capital. Observing the 75% price-cost

[6] The LRMC estimates are derived by calculating the present value of the estimated fixed and variable costs of a plant over its economic life and dividing that by the present value of the energy the plant is expected to produce. This is often called the levelized cost of energy, or LCOE. The hypothetical new generation plant may be a hypothetical (a) baseload coal or geothermal plant or (b) a combination of new wind or solar plant and associated firming generation, whichever is the cheapest.

margin in 2023 and naively thinking it will remain for the plant's life gives an internal rate of return (IRR) of 13.9%, substantially exceeding the investor's 7% cost of capital.

However, investors can expect generation will enter the market and drive spot and hedge prices closer to cost. The Authority's investment pipeline, for example, shows committed investments equal to 13% of existing capacity (1,456 MW), and actively pursued projects equal to 166% of existing capacity.[7] Under reasonable assumptions, the IRRs that can be expected by investors range from 7.6% to 9.9% (refer Appendix 1).

The Task Force is rightly concerned about the potential for unchecked market power in the generation market – it would not be doing its job if it was complacent about these matters. To that end, the Authority should request the business cases for all large generation investment decisions approved by electricity industry participants since mid-2018 and compile a one-off dataset of IRRs. The Authority could publish summary statistics, such as the mean or median IRR by year, type of investment and type of industry participant. I would be very surprised if the average or median IRRs for the generators greatly exceeded their weighted-average cost of capital.

2.2 Concerns about super-peak hedges are not credible or material

The Options paper states that the Task Force's competition concerns relate primarily to gentailer offers of firming contracts or hedges backed by flexible generation (3.26). It refers to evidence from the Authority's Issues paper on risk management that it is unable to affirm that super-peak hedges are likely to be competitively priced, and concerns that over a third of the time retailers receive only one offer in response to requests for shaped hedges (3.39).

In my view, the concerns about super-peak prices are neither material nor credible.

Materiality

The Options paper repeats the Authority's earlier conclusions that it believes baseload and peak hedge offer prices are likely to be competitive (3.39f). This is important because the Issues paper shows that adding a super-peak hedge to a portfolio of baseload and peak hedges provides minimal additional cover for a NIR.[8]

In other words, any NIR concerned about super-peak prices can obtain an essentially equivalent amount of hedge cover by purchasing products that the Authority affirms are likely to be competitively priced. How can the pricing of super-peak products *materially* affect the ability of NIRs to compete?

To be more specific, let p denote the offer prices for super peaks and let p^* denote the (unobservable) competitive price of those products. The Issues paper is saying that $(p - p^*)$ is not large enough for the Authority to be confident that super peak prices are

[7] https://public.tableau.com/app/profile/electricity.authority/viz/Investmentpipeline/Investmentpipeline

[8] Refer Figure 1 (p16), Figure 2 (p18) and Figure 3 in the Options paper. In each case, compare the red bar with the dark blue bar labelled Baseload & Peak. They are essentially equal in terms of volume of risk cover.

uncompetitive and not small enough for it to be confident they are competitive. So, $(p - p^*)$ is neither small nor large. It is moderate.

Let v denote the additional volume of cover provided by adding super peaks to a portfolio of baseload and peaks. My reading of the Issues paper (refer Footnote 8) is that v is very small. As $(p - p^*)$ is moderate, then $(p - p^*) \times v$ is small, suggesting a small profit impact for any NIR earning a normal return on investment.

Credibility

If any party firmly believes that super-peak hedges are materially over-priced, there is nothing to stop them from selling those products and 'creaming it' when spot prices during super-peak periods turn out lower than their hedge price.

Octopus Energy, Electric Kiwi and Flick Energy, for example, are owned by large parent companies that have the financial resources needed to pursue those opportunities at scale. Further, the hedge market is open to large financial firms in Australasia, not just to firms involved in electricity generation and retailing in New Zealand.[9]

It is not credible for the Authority to believe it has identified opportunities for excess profits, publicised them, and yet speculative activity has not reduced the gap.

2.3 Concerns about retail competition are unconvincing

Similar to its claims about generation, the Options paper states that gentailers have the opportunity and incentive to restrict retail competition because of their control of the flexible generation base, and therefore of the firming/hedging input their competitors need, at least in the short to medium term (3.51).

Opportunities and incentives

No evidence is offered regarding *opportunities* or *incentives* for gentailers to restrict retail competition. Instead, the Options paper claims that "we would typically expect to see small to medium retailers vigorously competing to grow their share, as occurred until 2020, including through innovation, agility and/or highly competitive pricing. That competitive impact appears to have stalled" (3.15).

Surprisingly, the Options paper makes no effort to explain why gentailer opportunities and incentives (supposedly) changed suddenly in or around 2020 and offers no evidence regarding opportunities and incentives.

Section 3 in this submission presents an alternative explanation for why NIRs have found it difficult to compete recently, which is to do with weaknesses in their business model. This explanation is consistent with NIRs being able to compete effectively before 2020 but only weakly since then.

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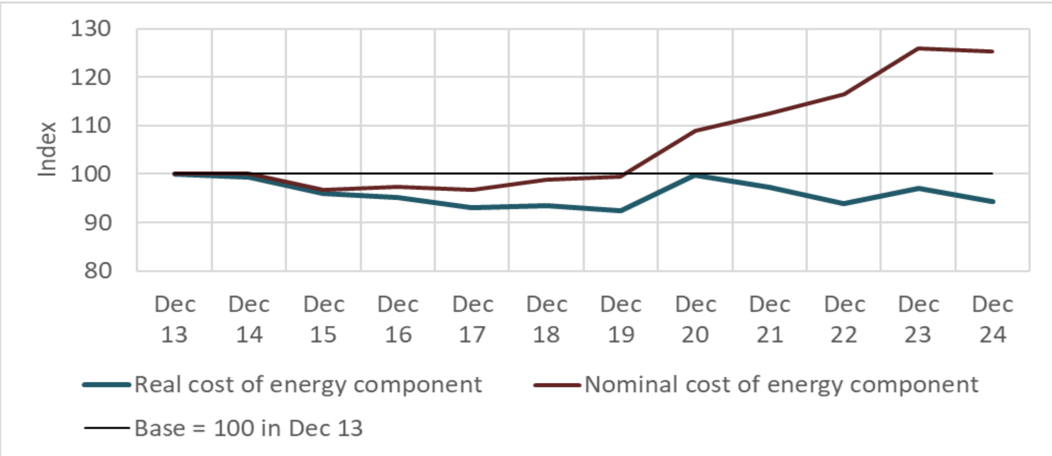
[9] For example, see https://www.afr.com/companies/financial-services/savvy-energy-traders-are-betting-the-house-on-australian-power-20240326-p5ffej.

Electricity prices (adjusted for inflation) are not consistent with a sudden weakening in retail market competition

I was surprised the Options paper did not consider retail prices. I was expecting a chart like Figure 3 below, which plots the trend in prices residential consumers paid for the energy component of their electricity bill. The nominal energy component is the household electricity bill minus transmission and distribution charges, divided by electricity consumed.[10] The real value is the nominal value divided by the Consumer Price Index (CPI).[11] Both are normalised to 100 in December 2013.

Figure 3: The real price of the energy component of household bills has declined since 2020



The real cost of the energy component has declined since 2020, which does not support concerns that retail market competition is weak. It is not possible to know whether real prices would have been even lower had NIRs been able to compete more effectively.

However, we know the 2013-18 period is a period of strong competition from NIRs. Some 20 additional retailers became active[12] and the aggregate market share of small and medium retailers nearly doubled, rising from 6.4% to 12.2%.[13] Despite that activity, the real cost of the energy component declined by only 6.5%, which is not materially greater than the 5.8% reduction from December 2020 to December 2022, when the small and medium retailers had flat market share, in aggregate.

Figure 4 plots the trend in real electricity prices for residential, commercial and industrial consumers (the data are for March years).[14] The real price for residential and commercial consumers is lower than in 2014, with commercial prices falling in real terms over 2016-

[10] The energy component is officially referred to as the 'energy and other' component. This was obtained from MBIE's Quarterly Retail Sales Survey (QRSS), available at https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/energy-prices/electricity-cost-and-price-monitoring.

[11] The CPI is from StatisticsNZ at https://infoshare.stats.govt.nz/SelectVariables.aspx?pxID=9ada1805-31d4-4eb2-96a7-d7f3910aa2f6.

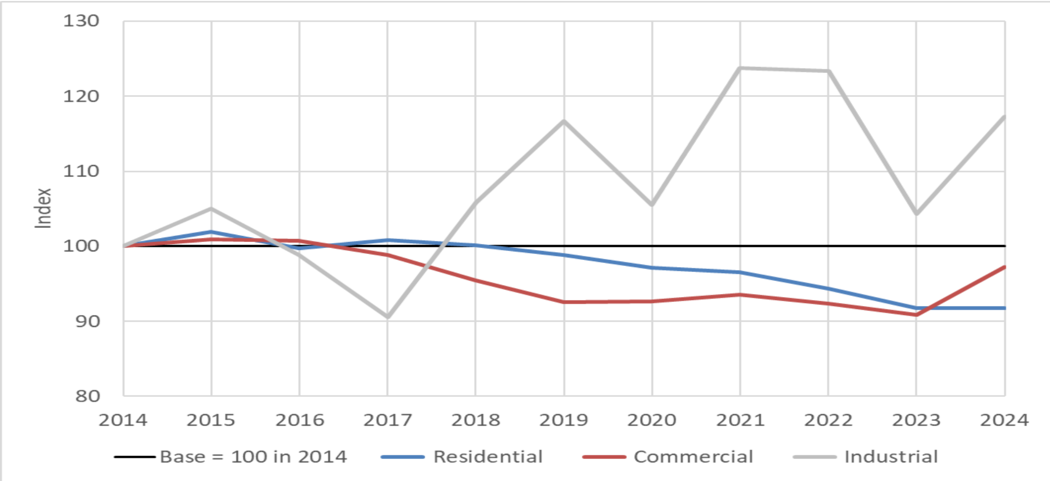
[12] Source: www.emi.ea.govt.nz/r/y01cr.

[13] Source: www.emi.ea.govt.nz/r/e5xlb. Small and medium retailers are all retailers excluding the five largest retailers by market share. Market share is the percentage of installation control points (ICPs).

[14] Source: https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/energy-prices

2019 and then remaining relatively stable until 2024. The volatility in industrial prices reflects timing of major contract renewals, significant variability in annual production and that they pay prices more closely aligned to wholesale market prices.

Figure 4: Real electricity prices have declined for commercial and residential consumers



The above charts do not lead me to be concerned about gentailer incentives to compete against each other. The charts are consistent with strong competition between them.

At the end of the day, what matters is retail market competition, not whether a particular business model is succeeding or not. It is a mistake to think that NIRs are the primary drivers of innovation. Some will be, some of the time. But my understanding is that several gentailers have been revamping their retail divisions and introducing more technology to reach and retain customers during this period of allegedly stalled competition.

2.4 The analysis of vertical integration is perplexing

The discussion of vertical integration bundles several matters together, making the analysis more obtuse than necessary. Nor does it consider the role integration plays in controlling arbitrage. My sense is that both factors have clouded the Task Force's understanding of the retail price implications of its proposal.

Integration vs contractual mechanisms for managing risk

The Options paper provides a list of the efficiencies of vertical integration (3.17) and acknowledges that the natural hedge from having generation and retailing in the same business is valuable for risk management. The paper concludes that price volatility can be managed through contracts and demand response (3.20). However, this misses the crucial point that contracts typically do not cover super long-term price risk, whereas vertical integration does.

In practice, retailers prefer contracts with durations ranging from 0 - 4 years (*short- and medium-term contracts*). Contracting any longer than four years leaves them very exposed to the risk of new entrants outcompeting them if hedge prices decline for a sustained period. As retailing requires minimal assets and is a thin-margin business, they can become insolvent relatively easily.

If incumbent NIRs contract short-term to manage their exposure to new entrant NIRs, they are exposed to price supercycles and competitive pricing by gentailers with long-lived assets. On the other hand, if they contract long-term to manage their exposure to supercycles, they are exposed to competitive pricing by new entrant NIRs. In both cases, it is critical they have a cash rich, flexible balance sheet or can readily call on shareholder equity or debt.

In practice, NIRs are reluctant to take contracts with terms reflecting the life of generation assets, or even for just 10 or 20 years (*super long-term contracts*).[15]

Vertical integration of generation and retailing addresses the absence of super long-term contracts between those activities. The retail arm of a gentailer is backed by super long-term generation assets and solvency constraints are more relaxed. This makes it viable for gentailers to cope with supercycles in wholesale prices, delivering value to customers by reducing their exposure to those price cycles (section 3 elaborates).

Generally, retailing to a large portfolio of residential customers is far less risky than contracting to retailers serving those customers. Although gross customer churn can be significant due to strong competition, net customer churn tends to be considerably lower and so a large portfolio of customers adjusts incrementally.

Further, it is well-known that integration occurs when contractual arrangements perform so poorly that the additional costs of operating as an integrated business are justified by the efficiency gains of displacing contracts. Most of the efficiency gains come from concentrating residual control rights over generation and retail with a single party rather than separate parties. This enables gentailers to better align their retail pricing with their longer-term perspective without fear of being arbitraged (refer section 3.1).

In summary, the Options paper implies that contracts are an effective risk-management substitute for vertical integration. But that is not the case because it does not provide super long-term risk management, which is what integration provides.

Concerns about the disconnect between ITPs and retail price setting

The Authority's review of internal transfer prices found that gentailers use them for accounting purposes rather than for setting retail prices. The Options paper states the internal transfer prices are not being reliably constructed to take account of future price expectations in a comparable way as hedge contracts sold to retailers (3.44).

It further states that the <u>disconnect</u> between the gentailer internal transfer prices and retail pricing suggests there may be an uneven playing field (3.45). It concludes the existing approach to internal transfer pricing is <u>not fit for purpose</u> in an environment where level playing field and margin squeeze concerns have been raised (3.46, the underlining is my emphasis).

These concerns underpin the Authority's non-discrimination proposal. In essence, the Authority is proposing to require gentailers to treat their internal arrangements as if they are governed by implicit contracts and to price them based on observable market rates for comparable contracts (15a, p75). It is also requiring these prices be set at levels that

[15] Later sections refer to the price of long-dated hedge contracts, defined by the Authority as contracts with 1 - 4 year durations. To minimise confusion, I refer to super long-term.

avoid any cross-subsidy that results in an internal business unit not being commercially viable on a standalone basis (17, p76).

Implicit prices are to be benchmarked against traded prices

The Options paper states that the underlying issue is that internal transfer prices are currently not set on a basis that would allow the Authority to make a meaningful comparison between how the gentailers treat themselves compared to how they treat third parties (3.43). It states that vertical integration, combined with internal transfer prices that are not fit for purpose, makes it difficult for any third party to assess price risks and competition issues (3.51c).

Hence, the proposal is for implicit contract prices to be based on observable market rates for comparable contracts, including baseload, peak and super-peak contracts adjusted for the internal requirements of the gentailer (15a, p75). The draft non-discrimination Principle 1 requires any adjustment to be cost-based and objectively justifiable (1, p73).

Which conduct is the Task Force seeking to address?

The Options paper is vague about where the misconduct lies. Is it in the retail or generation side of the gentailer business? The paper does not provide any numerical analysis of the size of the problem, so it is not possible to resolve the puzzle through that source.

Is the concern about mispricing on the retail side?

The implication of the statement that there is a disconnect between the gentailer internal transfer pricing and retail pricing is that the Task Force wants them to be connected. This implies the Task Force wants gentailers to set their retail prices based on implicit contract prices that are in turn benchmarked to ASX prices and other market prices.

Hedge market prices are currently elevated due to supply side factors. If the Task Force believes gentailers are cross-subsidising their retail arms, then prohibiting cross-subsidies will inevitably increase retail prices.

Yet the Options paper discusses this risk only once and does not provide any numerical analysis of it.[16] This implies the Task Force believes the mispricing is in the generation side of the business, discussed next.

Is the concern about mispricing on the generation side?

In discussing foreclosure by vertically integrated businesses, the paper states this would involve gentailers acting upstream (at the generation level) to disadvantage NIRs. For example, this could include imposing a margin squeeze or refusing to supply hedge products to NIRs (3.23b). This implies the mispricing is on the generation side of the business.

But if the Task Force believes gentailers are cross subsidising their generation arms, then it is implicitly claiming that the non-discrimination obligations will reduce ASX and OTC hedge prices. Alternatively, the Task Force may be creating an obligation to sell hedges below prevailing market prices, enabling arbitrage by other parties and disincentivising

[16] I am concerned the Options paper downplays this risk and discuss it further in section 4.

investment in generation assets. Both approaches would be consistent with their concern that the Authority's risk management review was unable to affirm that prices for super-peak hedges were at competitive levels.

Perhaps the concern is about the availability of super long-term hedges?

Perhaps the Task Force believes the core problem is a lack of super long-term hedges for NIRs. Certainly, if NIRs had a balanced portfolio of hedges, they would be better able to ride through the price supercycle discussed in section 3, significantly reducing the risks for retail prices outlined in section 4 below.

But as discussed earlier in this section, incumbent NIRs would be exposing themselves to being undercut by new entrant NIRs when the supercycle ends. New entrant NIRs (those entering after the supercycle ends) would be able to buy short, medium and super long-term contracts at prices considerably lower than what incumbent NIRs will have paid. There is no reason to expect incumbents will want to expose themselves to that risk after having managed through the downsides of relying on short and medium-term hedges.

The Options paper mentions longer-term hedges only once, in Appendix C on mandatory trading of gentailer hedges. Hence, the rest of my commentary assumes the Task Force did not consider the absence of super long-term hedging was the core issue.

2.5 The proposed solution is misguided and not 'a quick fix'

The Options paper states that non-discrimination obligations would give NIRs and independent generators access to products (for example, hedge contracts, firming) on substantially the same terms as gentailers supply themselves internally (4.16, 5.5 and 6.18(c)-(d)). However, that is not what the non-discrimination obligations require, as elaborated below.

The proposal implies internal hedging is short- and medium-term

As discussed at the start of section 2.4, the standard economic analysis of integration is that it displaces inefficient or ineffective super long-term contracts between the buy and sell sides of an exchange. So, paragraph 4.16 implies gentailers must offer super long-term contracts to NIRs and independent generators.

But that is not what the non-discrimination obligations require. They require gentailers benchmark their implicit contract prices to observable market rates. This implies the Task Force thinks the implicit contracts are short- and medium-term, because observable market rates do not exist for super long-term contracts.[17] As discussed in section 3, this approach is likely to have significant retail price implications.

The short- and medium-term focus arises because the Options paper flips between two different notions. Paragraph 4.15 requires gentailers treat themselves substantially the same as they currently treat non-integrated competitors, whereas paragraph 4.16 requires the converse: gentailers must treat others the same as they currently treat themselves.

Although the paper states that the Authority respects the right of businesses to choose their own structure and prefers to not unnecessarily restrict those choices (3.19), it is in

[17] Section 2.4 defined super long-term as terms matching generation asset lifetimes, or 20+ years.

fact proposing very significant restrictions. Although it may not think so, the Task Force is effectively requiring gentailers to take a short-term approach; that is, to adopt the inherent limitations of the non-integrated model. It is overturning the key feature of integration, which is that it displaces the contractual approach to managing price supercycles.

The Authority's proposal has significant implementation issues

A fundamental problem with implementing the requirements of paragraph 4.16 is that hedge contracts are easily arbitraged. If gentailers base their offers on a subjective assessment of prices implicitly charged to their own retail division, then contract buyers can arbitrage the price differences. For example, any party, including other gentailers, could buy contracts from the lowest price gentailer and sell contracts at a higher price (pitching just under the next highest gentailer offer), and so on.

In other words, it is infeasible for each gentailer to treat others the same as they currently treat their own retailer. The best they can do is offer contracts based on prevailing hedge market prices, with a modest and temporary margin above or below.

The same logic also applies to Principle 1 in Appendix B, which requires there can only be differences between internal and external offers where there are cost-based, objectively justifiable reasons. Cost-plus pricing is misguided in a market where arbitrage is relatively easy.

The proposal is costly and not a quick fix

The Options paper puts considerable store on the speed at which the proposal can be adopted in the Electricity Industry Participation Code (Code) (Table 2, p38). Inserting high-level principles in the Code does not amount to fixing something.

Further, the pros and cons discussion in Table 2 states that the principles-based approach would leave room for interpretation, may make it difficult to identify discrimination, and monitoring and enforcement could be challenging. This portends significant implementation issues and costs for gentailers, which is not mentioned in the table. Surprisingly, the formal evaluation in Table 5 (p50) makes the understatement that "Gentailers will incur some systems costs to ensure compliance."

Table 2 also states that additional detail may need to be prescribed over time to identify discrimination, such as accounting separation and improved disclosure of internal transfer prices. The earlier discussion of that approach rightly expresses concern about the scope for debate about whether different approaches are efficient and/or justified by different circumstances (4.14). Surely the same applies to whatever details gentailers include in their compliance report.

Further, a gentailer can do its best to comply with the non-discrimination rules but will be dragged down by the lowest common denominator. That is, if the Authority is not happy with how one gentailer has complied with the principles it could impose step 2 or step 3 on all gentailers. Presumably the Authority will publish criteria for adopting these steps, however it seems likely they will provide minimal guidance.

Overall, the proposal risks harming the reputation of the retail electricity market if the Authority assesses compliance breaches, tightens the rules, creating more compliance breaches, and on and on. Reputational harm can be very costly, and unnecessary if it derives from vague rules.

2.6 A numerical cost-benefit assessment is needed

The Options paper uses several criteria to determine which of their options is preferred but does not appear to have undertaken an indicative cost-benefit assessment (CBA) and the paper does not signal any intention of doing so.

In the next stage of this work, I would hope to see a numerical cost-benefit assessment of the proposal rather than a high-level qualitative assessment of the competition, reliability, efficiency and other effects of the proposal.

3 An alternative perspective about market performance

Ronald Coase, a key figure in the modern analysis of vertical integration, has remarked:

> *If an economist finds something—a business practice of one sort or another—that he does not understand, he looks for a monopoly explanation. Coase (1972, p67)*

In that vein, it is prudent to consider non-market power reasons for why there is a perception that NIRs in general have struggled to compete since 2020. It is not obvious to me why gentailer structure and market position – which has barely changed since 2010 – was benign for NIRs through to 2020 and then hostile after that. Likewise, why has protection from spot price risks during super-peak periods supposedly become a more essential input for NIRs than pre-2020?

As mentioned earlier, in my view the key issue is not gentailers overpricing their super-peak hedges or failing to set their retail prices according to their internal transfer prices. Rather, the key issue is that NIRs are poorly placed to offer super long-term price smoothing services to consumers, as they do not own assets or have capital structures that enable them to ride through a supercycle.

3.1 Segmentation and arbitrage in electricity markets

A pure arbitrage opportunity occurs when a party can make a riskless profit by buying in one market and simultaneously selling in another. Markets are segmented when price differences do not attract sufficient arbitrage activity to close the price difference.

Variable-volume contracts are segmented from the hedge market

It is not feasible for consumers, of any size, to arbitrage price differences between the hedge market and their variable-volume contracts. This is because the volumes in these contracts are metered by the retailer or an independent third party. Selling an offsetting hedge contract would increase consumer risk, not reduce it. There is no arbitrage opportunity.

In other words, variable-volume contracts are physical offtake contracts. Retailers can offer discounted prices on variable-volume contracts without the risk of their customer selling offsetting contracts on the ASX market and coming back for another contract, *ad infinitum*. Variable-volume contracts are segmented from the hedge market.

Standardised hedge contracts are easily arbitraged

It is widely accepted that financial contracts are often subject to arbitrage risk, and the more standardised they are, the easier it is to arbitrage them.

This is important because, unlike in most other industries, contracts between electricity generation and retail are purely financial, as electricity retailers never take physical delivery of electricity. They are financial intermediaries, not physical retailers.

The upshot is that generators cannot offer contracts to NIRs at prices materially below market prices without risking being arbitraged on the ASX futures market. It also means that market-making arrangements effectively constrain or discipline any price misalignments between hedge products.

Vertical integration prevents arbitrage between generation and retail

Although the Options paper lists the potential efficiencies with integration (3.17), it does not discuss the fundamental role of residual control rights, which is the underlying attribute that enables those efficiencies.

In essence, integration gives residual control rights over both generation and retailing to gentailer chief executives.[18] They use those rights to remove any risk of the managers of the retail arm arbitraging the managers of the generation arm, and vice versa.

This control assists gentailers to offer greater price-smoothing services to consumers, materially improving their welfare when supply side shocks would otherwise create more volatile retail prices (refer section 3.3).

3.2 Price supercycles occur from time-to-time in commodity markets

Over the last six and half years, ongoing increases in the cost of gas and uncertainty about gas availability has driven a prolonged increase in electricity spot and hedge prices in New Zealand. There were also significant uplifts in the cost of solar panels and wind turbines with the Russian invasion of Ukraine in February 2022 and President Biden's Inflation Reduction Act in August 2022, however those prices have reversed significantly (in real terms).

Figure 5 plots the average price of long-dated baseload quarterly electricity futures contracts at Benmore over the period 2 July 2018 to 31 December 2024.[19] The cumulative price increase over that period was 102%, and the corresponding increase at Otahuhu was 130%.[20] The average increase across both locations was 116%.

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[18] Technically speaking, the residual control rights are held by the owner of the entity. The owners delegate residual decision rights to the board, who in turn delegate a subset of those rights to the chief executive, and so on down the organisation.

[19] The corresponding chart for Otahuhu is similar and available at www.emi.ea.govt.nz/r/z3vh0.

[20] The Benmore price increased from $69.59 to $140.81 and the Otahuhu price from $76 to $175. All prices are $ per MWh.

Figure 5: Average ASX prices for long-dated baseload electricity futures contracts at Benmore

In real terms, after adjusting for consumer price inflation, the average price of Benmore and Otahuhu hedges increased 90%. It is widely expected that elevated prices could last another two or three years before reverting to a downwards trajectory.

These types of long run price cycles in commodity markets are called *supercycles*, as they reflect structural factors, such as macroeconomic, technology and geopolitical developments.

3.3 Considerable price smoothing has occurred over the current supercycle

Electricity is a necessity for most small consumers, and on average it accounts for 4.2% of household disposable income.[21] As a result, the price elasticity of demand is relatively low, making it feasible for retailers to increase residential electricity prices to maintain their profit margins without suffering significant demand reductions. However, real price rises have not occurred over the current supercycle.

Adjusting for inflation, the real price of household electricity declined by 6.7% over July 2018 to December 2024.[22] However, the household bill includes transmission and distribution charges, which are largely set by regulators. The energy component of household electricity bills more closely reflects the competitive segments of the electricity market. The real price of this component declined by 0.2% over 2018 –2024.[23]

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[21] According to the QRSS, average residential expenditure on electricity was $2,378 in the year ended June 2023. According to Statistics New Zealand, average annual household equivalised disposable income (after tax and transfer payments) was $56,919 over the same period. The income statistics are available at https://www.stats.govt.nz/information-releases/household-income-and-housing-cost-statistics-year-ended-june-2023/.

[22] The nominal price increased 20.1% (QRSS, ibid) whereas the CPI increased by 26.8% over the same period.

[23] The nominal price of the energy component increased 26.6% (QRSS, ibid).

With hedge prices increasing by 90% in real terms, the 0.2% decline in the energy component reflects considerable price-smoothing. The underlying reason for this outcome is that a significant portion of residential and SME consumers prefer stable electricity prices and retailers expected the elevated hedge prices would be temporary.

My understanding is that, in most years since mid-2018, generators and retailers have expected wholesale prices to be elevated for two or three more years and then revert towards pre-2018 levels (in real terms) and reduce even further in the very long-term as the cost of wind, solar and batteries continue to decline.[24] In these circumstances, it can be optimal for retailers to try to ride through the turbulence to avoid annoying customers with price rises that will later be reversed. This promotes consumer welfare and saves the retailer the cost of winning back customers. It is easy to see how this can be a competitive equilibrium.

However, as explained in detail below, an unusual series of large adverse supply and demand shocks have occurred since 2018, prolonging the elevated hedge prices far longer than any retailer initially anticipated. The outcome is that retailers have probably provided deeper and longer price smoothing than they would have done if they had perfect foresight and knew wholesale prices would be elevated for a decade or so.

Another factor is that electricity retailers appreciate that sharp and ongoing increases in real retail price rises would likely have induced a consumer backlash and political intervention to cap residential prices, as has occurred in other jurisdictions (eg, Australia, UK). No retailer benefits from price caps in the long-term, as discussed in section 4.3.

3.4 Most supply and demand shocks were expected to reverse in due course

A series of large adverse shocks have affected demand and supply since 2018, and especially since mid-2021. Many of the adverse shocks originated from the prices and availability of domestic gas and Indonesian coal.

Figure 6 shows average prices for short-dated and long-dated electricity futures at Benmore since the start of trading on the ASX market in 2009.[25] It is clear that both prices have become far more volatile post-2018.

The increased volatility of the long-dated prices implies that expectations about the longevity of supply and demand shocks were volatile, indicating high uncertainty. Prior to 2024, significant increases in long-dated prices were followed by significant retreats.

[24] The Authority can test this claim in two ways. It can obtain the wholesale market price forecasts prepared by retailers for each year since 2018 – these extend far longer than the 3-4 years ahead for ASX futures contracts. Secondly, it can compile an index of prices for long-term contracts and adjust for ASX prices, to obtain an 'y in x' years assessment of price expectations. For example, suppose a long-term hedge contract is signed for z=10 years. Backing-out the effects of elevated prices for x years (as measured by ASX prices) will enable the derivation of the implied price for electricity for y years starting in x year's time (y = z - x).

[25] The corresponding chart for Otahuhu prices is available at www.emi.ea.govt.nz/r/1yrjn.

Figure 6: Prices for short- and long-dated electricity futures contracts at Benmore, 2009-25

Drilling into the details (dates for adverse supply shocks are highlighted in bold):

- **Mid-2018**: *Pohokura gas outages*. Significant unplanned gas production outages at Pohokura. Prices for long-dated futures contracts at Benmore were only slightly elevated, at around $88.
- **Early 2019**: *Uncertainty about gas outage*. Realisation that Pohokura outages are longer lasting than initially thought and it becomes uncertain if production will return to pre-outage levels. Long-dated Benmore prices remain around $88.
- March 2020: *Covid-19 lockdown*. Long-dated Benmore prices had been declining since 4 March and neither the announcement of the lockdown on 23 March nor the lockdown materially affected those prices.
- 9 July 2020: *NZAS termination*. Meridian announces NZAS' intention to close its Tiwai Point aluminium smelter and terminate its electricity contract with Meridian, causing long-dated Benmore prices to fall to $50. This led to expectations that elevated hedge prices would not return
- 27 August 2020: *NZAS may be on again*. NZAS announced it was in talks with generators, hoping to secure a short-term contract to tide it over until upgrades to the transmission grid in the Lower South Island would allow it to export more power to the North Island. Long-dated Benmore prices increased steadily through to 3 December, from around $50 to $87. Although modestly higher than the average for 2010-2017, this further cemented expectations that elevated hedge prices would not return.
- 14 January 2021: *Stop-gap NZAS contract*. Meridian announces a short-term agreement with NZAS, keeping the smelter operating through to December 31,

2024. Long-dated Benmore prices had been rising ahead of the announcement. They jumped from $79 to $115 by 11 February 2021.

- **Mid-2021**: *Prices for Indonesian coal trebled by middle of 2022*. This followed China's ban on Australian coal imports in late 2020, increasing Indonesian coal exports to China. Long-dated Benmore prices increased steadily towards $100 and hovered around that mark until mid-February 2022.

- **23 February 2022**: *Russia invades Ukraine*. This caused record international wholesale gas prices and significant volatility due to supply restrictions, sanctions and sabotage. Europe became more desperate to increase their installation of renewable energy. Increased demand for solar panels, wind turbines and batteries caused the prices for those components to spike by 30-40% in 2022-23. Long-dated Benmore prices jumped 50%, from $100 on 2 February to $150 by 16 May.

- **August 2022**: *US ramps up renewable energy subsidies*. President Joe Biden's Inflation Reduction Act gains congressional approval. This further increased global demand for solar panels and wind turbines.

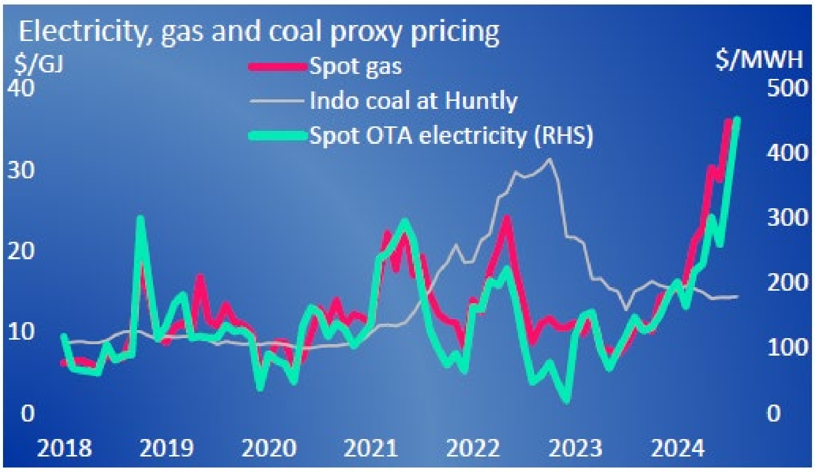
- **17 July 2023**: *NZ gas reserves falling*. MBIE releases data showing a 17% decrease in proven plus probable (2P) reserves and states that natural gas held in reserve will last less than 10 years. Long-dated Benmore prices barely move, hovering around $115 - $120.

- **Early May 2024**: *Gas production falls more quickly than expected*. The Gas Industry Company (GIC) reports that gas supply was at the bottom of expected volumes for the year, and insufficient gas is available to meet all contracted demand. Long-dated Benmore prices continued to hover around $115 - $120.

- **22 May 2024**: *Kupe KS-9 drilling results disappointing*. Genesis Energy and NZ Oil & Gas announced that attempts to increase gas production from the Kupe field had failed. Long-dated Benmore prices continued to hover around $115 - $120.

The increasing scarcity of gas from mid-2023 is reflected in spot gas prices, which fed through to spot electricity prices and eventually to prices for long-dated hedges (refer Figure 7).

Figure 7: Spot electricity prices are highly correlated spot gas prices



Source: Meridian Energy Limited

- 31 May 2024: *NZAS announces new long-term contracts*. NZAS signs contracts with Meridian Energy, Contact Energy and Mercury Energy to power the Tiwai Point aluminium smelter for another 20 years. This provided the sector with much-needed certainty from New Zealand's largest electricity user. The contract with Meridian contains significant elements of callable demand response. Long-dated Benmore prices continue to hover around $115 - $120.
- **Mid-August 2024**: *Worsening gas shortages for electricity generators leads them to pay extraordinarily high prices to Methanex to temporarily shut its production.* Contact Energy and Genesis Energy agree terms with Methanex to idle its remaining Motunui plant and re-route its gas to Contact and Genesis' for use in their closed-cycle thermal generation plants.

Reverting back to Figure 6 (page 23), long-dated prices were reasonably aligned with short-dated prices pre-2018, but this changed in mid-2018. Since then, long-dated prices are almost always lower than short-dated prices, consistent with my view that prior to 2024 the market expected most of the adverse supply shocks to be temporary. The Authority could examine this further by compiling a yield curve for ASX traded hedge contracts.

3.5 Incumbent gentailers can provide price smoothing for long periods

In practice, generators with a large proportion of long-dated assets and moderate debt levels are well-placed to ride through a prolonged period of adverse price shocks, and the same applies to gentailers.

All incumbent gentailers in NZ have asset portfolios that mainly comprise long-dated generation assets. This reflects the fact that generation assets are often exceptionally long-lived – wind farms have 20-25-year expected lifetimes, solar farms up to 35 years, and hydro and geothermal far longer than that. It also reflects that minimal demand growth over the last 34 years (1990 - 2024) has meant only a modest amount of new generation has been needed to replace retiring plant.

Moreover, as generation is a highly capital-intensive business, earning a normal return on generation produces large cash flows, and large net cash flows if they have modest debt levels. In contrast, electricity retailing operates on low capital costs and is a thin margin business.

In principle, incumbent gentailers need to earn a normal return from their retail division over the super long-term to satisfy investors they should remain integrated. This means they may try to recoup their retail losses when favourable shocks occur, however they will be constrained by new players entering the market to take advantage of low wholesale prices.

The upshot is that incumbent gentailers are well-placed to smooth residential retail prices for a prolonged period, which benefits consumers. In contrast, NIRs are generally poorly placed to do that, as discussed next.

3.6 Non-integrated retailers have poor long-term price-smoothing capability

NIRs tend to have a portfolio of short-term hedges, with the tenor of their longest-dated hedges typically no longer than 4 years. The weighted average tenor of their hedge portfolios tends to be around 18-24 months. This means fully hedged NIRs experience large cash outflows when wholesale prices increase sharply and remain elevated well beyond their average contract tenor.

In principle, incumbent NIRs should be better placed to cope with serial adverse supply shocks, as they could have secured long-dated power purchase agreements, but that does not appear to have occurred in practice. One reason is the reasonably static level of electricity demand since 1990, but especially since 2000. There has been very limited need for new generation, so retailers entering the market since 2000 have had limited opportunity to acquire power purchase agreements.

3.7 New entrants tend to struggle when adverse market shocks occur

NIRs entering the market since 2018 are likely to be very poorly placed to withstand adverse market shocks. Most will not have reached the scale they needed to achieve profitability in a steady-state market, let alone in a market suffering a prolonged period of high wholesale prices.

The same logic applies to new entrant gentailers. This is because their new generation assets will have been costly to purchase and install (one of the reasons for the high hedge prices), so they will be competing for consumers with an elevated cost base. In other words, vertical integration is not in itself the saviour for a retailer.

For example, suppose a potential entrant to the residential retail market has access to enough gas to run a 100 MW peaker plant. There are no problems sourcing the capital equipment to install the gas peaker and solar and wind plants, and doing so completely avoids the hedge contracting concerns discussed in the Options paper. Based on spot gas prices since 2020, it would be straight forward for the Authority to show that this gentailer would not be a viable proposition at current residential prices.

3.8 Retail market outcomes reflect market asymmetries, not market power

The key issue is not that gentailers are trying to overprice their OTC hedge offers to NIRs to make it difficult for them to compete. Arbitrage prevents that becoming a material problem.

Rather, recent retail market outcomes reflect several asymmetries:

- Most shocks since 2018 have been adverse supply shocks, and most have been longer lasting than anticipated. There has been only one favourable demand shock, which lasted only seven months (July 2020 – January 2021).

- There is a fundamental asymmetry between hedge and retail markets. Prices for hedge products must align with expected spot prices to avoid arbitrage, whereas prices for variable volume retail supply contracts do not have to align.
- Incumbents with long-lived generation assets are better placed to ride through prolonged periods of adverse shocks than competitors with short-lived assets.

A prolonged period of price smoothing can be a competitive equilibrium because it serves the interests of retail consumers, and suppliers serving a large share of the market are able to serve those interests. It would occur even if the electricity market had 20 incumbent gentailers.

For example, assume each incumbent gentailer has a 5% share of the generation market, a 4% share of the retail market and the remaining 20% of the retail market is served by a single NIR. Under these hypothetical circumstances, no gentailer could materially influence hedge prices by refusing to supply some hedges or offering them at prices above its competitors. But, as each incumbent gentailer has long-dated generation assets, they are able to withstand repeated adverse supply shocks for a prolonged period.

4 If effective, the proposal carries significant price risks for households

The Options paper mentions only once that its proposal carries the risk of a short-term increase in retail prices. The risk is not even mentioned in the announcement material.[26] This is very surprising, given the severe cost-of-living pressures households have been experiencing recently, and the political sensitivity of higher electricity prices for households.

4.1 Household electricity prices are likely to rise sharply in the short-term

The Options paper states that any level playing field (LPF) measure runs some risk of a short-term increase in retail prices, "to the extent that Gentailers may not be currently passing through the full extent of wholesale price increases over recent years." It dismisses the risk, saying "That is the trade-off for longer term competition benefits" and seeks to minimise the issue by saying the risk is smaller for the non-discrimination proposal than for stronger interventions such as corporate separation (5.12). Nowhere does the Options paper indicate the potential size of the price increases.

However, it is irrefutable that price smoothing by gentailers has kept household electricity prices substantially lower than what would otherwise occur. As mentioned in section 3.3, in real terms long-dated hedge prices have increased by about 90% since July 2018 yet the energy component of household electricity prices has been flat over that period after adjusting for inflation.

It is notable the Authority suspended producing its *retailer cost index* in 2020. This index estimated the residential price at which a new entrant retailer, without a generation

[26] https://www.ea.govt.nz/news/press-release/energy-competition-task-force-looks-to-level-the-playing-field-between-the-gentailers-and-independent-generators-and-retailers/

portfolio, could viably enter the market and sell to customers. Comparing movements in the index with measured retail prices would have been informative for the Authority's Options paper.[27]

In the absence of that information, I have estimated how much gentailer price smoothing is likely to have constrained household electricity prices. My calculations suggest those prices would have been 21-26% higher in December 2024, or $460-570 higher per year. The lower end of the estimate is based on the internal transfer prices Meridian has previously submitted to the Authority and the upper estimate is based on an average of prices for long-dated quarterly baseload contracts at Benmore and Otahuhu. Appendix 2 provides details of the calculations.

4.2 The short-term price jump could persist for many years

The Options paper admits there is a risk of increased household electricity prices, and it implies that stronger competition would reduce prices over the long run (5.12). This raises the question of how long it might take for household prices to return to the level they would be without the initiative and how long it would take for households to be better off.

Not surprisingly, the Options paper did not provide any timeframe estimates as it did not estimate the potential size of the price jump risk. To get an indication of timeframes, I made assumptions about the initial price jump and then considered two factors that may drive subsequent price reversion: competitive pressure and subsequent reductions in hedge prices.

Competitive pressure works very slowly

To get an indication of timeframes, I made the following generous assumptions:

- the lift in long-dated hedge prices and associated internal transfer prices is permanent
- the Authority's proposal causes a permanent, one-off, jump in household electricity prices by the lower of my estimate (ie, by 21%)
- the energy component accounts for about 57% of the total household bill, implying the 21% price jump arises from a 37% increase in the price of the energy component
- enhanced retail competition drives a 1.1-2.2% annual reduction in the real cost of the energy component. The 1.1% figure is discussed below. The 2.2% figure is simply a doubling of the 1.1% figure and is very generous.

[27] A chart of the Authority's retailer cost index is available at www.emi.ea.govt.nz/r/inawh. It compares the retailer cost index with the Quarterly Survey of Domestic Electricity Prices (QSDEP) reported by MBIE and the electricity component of the Consumers Price Index (electricity CPI) reported by Statistics New Zealand. The ratio of the retailer cost index to the QSDEP is quite volatile, as the index is calculated with a simple average of all electricity futures prices at Benmore and Otahuhu. This includes highly volatile short-dated hedge prices, which are heavily influenced by hydrological conditions. NIRs presumably take a longer-term view when setting their prices and deciding their marketing effort. It would be useful to calculate a version of the index based only on long-dated futures prices.

The 1.1% figure is the average annual rate of decline in the real energy component over 2013-18, as shown in Figure 3 (page 13). Enhanced competition over that period is unlikely to be solely or even mainly responsible for the 1.1% rate, however, let's assume it is. Under that assumption, it would take just over 28 years for the additional competitive pressure to bring household electricity prices back to their current level. If the 2.2% assumption is used, the timeframe reduces to 14 years. Details are provided in Appendix 2.

From a householder's perspective, the short-term price risk is not actually short-term, as they would be paying higher prices (than otherwise) for 14+ years. Although the initial percentage change in price is one-off, the price level remains high for many years as competitive pressure reduces prices gradually.

High hedge prices revert to normal in four years' time

In practice, the currently high hedge prices will eventually revert to their long-term average in real terms and will fall even further if solar and wind installation costs continue their previous downward trends.

Long-dated Benmore prices have generally exceeded $150 since mid-January 2025, due to ongoing concerns about gas and coal prices and availability amid an intensifying drought ahead of winter 2025. However, hydro lake levels were above average over late spring and into mid-summer (7 October 2024 – 17 January 2025), yet long-dated Benmore prices ranged $125-$150.[28] This suggests wholesale prices are expected to remain elevated over the next three to four years.

For brevity, assume the average price is the mid-point, which is $137.50. This is a $50.05 gap from the $87.45 ASX price needed to bring household electricity expenditure back to the 2024 level of $2,343. The $87.45 price is slightly lower than the $95 nominal price needed to maintain the real price of long-dated contracts at their value in June 2018.[29]

My calculations assume the $50.05 gap persists for one year and then reduces by a third each year to reach the neutral price of $87.45 at the start of the fourth year. Over that period, the average household would pay about $818 more in electricity bills. Under the very generous assumption that enhanced competition would reduce household electricity prices by 2.2% annually, it would take over 15 years for households to break even (after the three years it takes for ASX prices to reach neutral). Details are in Appendix 2.

Concluding comment

The Authority needs to quantify the price jump risk, and present calculations of the welfare implications for consumers.

[28] See www.emi.ea.govt.nz/r/3apsc for hydro lake levels and Figure 5 (page 22) for long-dated Benmore prices.

[29] Benmore and Otahuhu prices for long-dated baseload contracts averaged about $75 in real terms in June 2018. Cumulative CPI inflation since then was 26.8%, so in December 2024 a $75 real price is $95 in nominal terms.

4.3 The proposal increases the risk of price caps, which harm non-integrated retailers

Retail electricity prices will mimic supercycles

If the non-discrimination principles are effective, the ultimate consequence is to drive gentailers to adopt shorter-term pricing for residential and SME consumers. This implies larger cycles or swings in retail prices than have occurred recently.

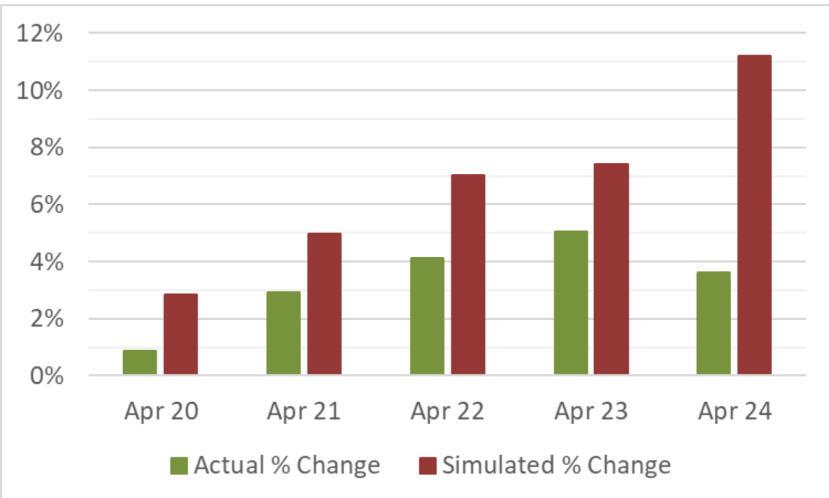
The size of the retail price swings depends on the timeframe for assessing the 'no cross subsidy' rule. This is because the proposed non-discrimination obligations would require gentailers to avoid cross-subsidies that result in an internal business unit being commercially unviable on a standalone basis (Appendix B, para 17).

The commercial viability of standalone business is typically assessed over a period, as many businesses incur losses from time to time and it is not unusual for them to operate at below normal returns on capital for several years. Their ability to withstand losses and below-normal returns depends on their level of financial reserves and the risk appetite of its owners.

If the Authority interprets commercial viability on an annual basis, then gentailers will need to adjust their retail prices in lockstep with annual changes in the value of their implicit contracts (which are to be marked against market prices for hedges). Large changes in retail prices are likely to occur from time to time, as shown in the chart below.

Figure 8 compares the percentage change in actual versus simulated retail prices, where simulated prices are the prices that Meridian would have had to charge if it was required to set its prices based on the internal transfer prices reported to the Authority.

Figure 8: Retail price changes with no cross-subsidy, for years beginning 1 April



On the other hand, if the Authority allows a longer period for determining commercial viability, price adjustments can be driven by a smoothed function of internal transfer prices. This would reduce the risk of price shocks for small consumers, although of course eventually they will pay the full cost.

However, there are two obvious downsides to the smoothed approach. First, it leaves NIRs with slower revenue growth than their cost growth until internal transfer prices have stabilised for a period. Second, it leaves existing gentailers and NIRs exposed to cherry-picking by new entrant retailers.

The risk of retail price caps is increased

The Options paper does not consider the longer-term consequences of larger swings in household electricity prices. For example, there is no mention of the price controls introduced in other markets due to voter backlash to large jumps in household electricity bills. The United Kingdom (UK) introduced price caps in January 2019[30], and Australia followed in July 2019.[31] Many other European countries introduced some form of price cap in 2022.[32]

There is little reason to assume the political incentives are materially different in New Zealand. In my view, introducing the non-disclosure obligations materially increases the risk that a future government will introduce price caps.

Retail price caps often bankrupt non-integrated retailers

No retailer benefits in the long-term from inducing a consumer backlash that leads to price caps. The experience in both Australia and the UK is that NIRs suffer disproportionately under those regimes. Many go broke because regulators are slow to adjust the price caps and do not adjust them fully, to reduce consumer backlash and further political intervention.

In the UK, for example, 31 energy companies ceased trading over 1 January 2021 to 18 February 2022.[33] These failures occurred due to high wholesale gas prices (before Russia invaded Ukraine).

5 Allow the negotiate-arbitrate option as a safe harbour

Section 4 identified three key risks with the Task Force's proposal:

1. Short-term retail price risks, which my calculations suggest are likely to be material for households and small businesses.
2. Longer-term solvency risks for NIRs as the proposal increases the prospect of a future government capping retail prices, which in practice disproportionately harm small retailers.
3. Longer-term reputational risks for the electricity market due to difficulties objectively demonstrating compliance with the proposed non-discrimination rules.

The first two risks arise from the specifics of the non-discrimination obligations. These risks would be avoided by allowing the negotiate-arbitrate option as a safe harbour. That is, any gentailer complying with the safe harbour provisions would be exempt from most of the non-discrimination regime.

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[30] https://www.ofgem.gov.uk/energy-policy-and-regulation/policy-and-regulatory-programmes/energy-price-cap-default-tariff-policy

[31] https://www.aer.gov.au/industry/registers/resources/reviews/default-market-offer-prices-2025-26

[32] https://www.en-former.com/en/price-caps-have-become-the-norm-across-europe/

[33] https://www.forbes.com/uk/advisor/energy/failed-uk-energy-suppliers-update/

In addition to reducing risks, the proposed safe harbour is warranted because the problem definition underpinning the Authority's proposal is strongly contested, it is broad sweeping rather than targeted, and it is not as practicable as indicated in the Options paper. It creates considerable uncertainty and costs for gentailers and non-integrated parties.

The proposed safe harbour benefits all retailers. It provides an option that gentailers can be certain meets the Authority's aims for a level playing field between gentailers and non-integrated parties. And it gives non-integrated parties a practicable way in which to ensure they have access to hedge contracts at competitive prices.

5.1 Proposed features of the safe harbour

The safe harbour would be introduced through a Code provision allowing gentailers to elect a defined negotiate-arbitrate regime. This approach is well-suited for addressing concerns about the pricing of bespoke OTC hedge products, as several of the cons become pros when introduced as a safe harbour option.

The key features would be those outlined in the Options paper, but with the scope of the negotiate-arbitrate obligation limited to the products the Task Force is concerned about. Appendix D (paragraph D.9) expresses a short-term concern about competition in the provision of short duration flexibility, as it recognises that falling hardware prices and increased availability of batteries should address those concerns. It expresses a longer-term concern about the provision of flexible supply providing cover for periods of a week or more (*longer duration flexibility products*). This suggests the negotiate-arbitrate approach could apply in the near term to OTC super peak products, with a trigger to remove them from the regime once competitive supply is more demonstrable. Longer duration flexibility products may remain in the regime for longer, however, a defined trigger for removing them should also be adopted.

Key features

The key features of the safe harbour regime could take the following:

1. *Safe harbour entry* - If a gentailer wishes to use the safe harbour option, it must formally notify the Authority of its choice by the date that the non-discrimination obligations first become effective and by every anniversary date thereafter.
2. *Safe harbour exit* - Gentailers using the safe harbour option cannot withdraw from it within 12 months of electing to use the safe harbour.
3. *Eligibility* – Only negotiations with non-integrated retailers would be covered by the regulated arbitration regime and only to the extent their retail book is uncovered.
4. *Arbitration products* - OTC super peak and longer duration flexibility products. Baseload and peak products are excluded.
5. *Arbitration principles* - Gentailers are required to provide access to arbitration products on fair, reasonable and non-discriminatory terms (FRAND).
6. *Arbitration method* - Final-offer arbitration occurs if commercial negotiations are unsuccessful. As the Options paper states, this will incentivise the negotiating

parties to submit their best offers to the arbitrator and it would alleviate information asymmetry issues for the arbitrator (4.23).

7. *Arbitrator selection* - The negotiating parties can appoint any arbitrator by agreement. If the parties are unable to agree on the arbitrator within a period specified in the Code, the gentailer and counterparty would have alternate rights to appoint an arbitrator from an Authority-approved list of qualified independent experts.[34]
8. *Arbitration timeframe* - The negotiating parties can decide the arbitration timeframe by agreement. A default timeframe will be specified in the Code to guard against delaying tactics.
9. *Arbitration costs* - The arbitrator's costs are paid by the party that loses the arbitration. Ordinarily, each party pays their own costs of participating in arbitration. The arbitrator has authority to require a party to pay costs to the other party if the arbitrator determines the initiating party is acting vexatiously.
10. *Contract disclosure* - The arbitrator lodges all arbitrated contracts with the Authority and the Authority publishes a summary of the key terms and conditions. Any arbitrator currently handling a case for negotiating parties has full access to the details of any arbitrated contracts for which at least one of the negotiating parties has been party to over the previous 12 months.

Exemptions from non-discrimination requirements

The safe harbour provisions would exempt the gentailer from most of the non-discrimination regime:

- *Exempt from most non-discrimination principles* - Any gentailer using the safe harbour option would be deemed to be compliant with the principles of the non-disclosure obligations, except for draft Principle 5 (or P5).[35] This principle requires gentailers protect buyer confidential information and not disclose this information to any internal business units that compete with the buyer. In my view, this should apply regardless of the regime applying to the gentailer.

  For the avoidance of doubt:

  - The gentailer would not be required <u>by the Code</u> to provide a cost-based, objectively justifiable reason for discriminating (P1) as final-offer arbitration incentivises this approach anyway.
  - The gentailer would not be required to establish an economically meaningful portfolio of internal transfer prices that reflects its internally traded hedges (P2), as FRAND principles do not require this approach.

[34] That is, if a gentailer appointed an arbitrator from the list for a previous arbitration involving the gentailer, then whoever is the counterparty in the current arbitration has the right to appoint an arbitrator from the list. The next time the gentailer is subject to an arbitration request, the gentailer has the right to appoint from the list.

[35] The draft principles are in the Options paper, Appendix B, p73.

- The gentailer would not be required by the Code to provide an objective assessment of the risk of trading with a buyer when setting their credit terms and collateral arrangements (P3) as final-offer arbitration incentivises this approach anyway.
- The gentailer would not be required to make available to any buyers any commercial information relating to risk management contracts made available to its internal business units (P4). Gentailers have incentives to make this type of information available to parties during negotiation to secure their agreement, and to the arbitrator if arbitration is required.
- The gentailer would not be required to establish, maintain, keep and disclose records that demonstrate its compliance with the standard non-discrimination principles (P6). This is unnecessary for voluntary agreed contracts (the Authority has disclosure requirements for these anyway) and the arbitration process ensures, as best as practicable, that arbitrated contracts satisfy FRAND principles.

- *Exempt from most reporting requirements* - The gentailer would be exempt from the detailed record-keeping, reporting, certification and publication requirements in outlined in paragraphs 7 – 11 in Appendix B.

Arbitration would work well for a subset of OTC products

The Options paper says the negotiate-arbitrate approach may face challenges where there is inherent uncertainty and information asymmetries regarding highly material issues such as future hydrology risk (4.25a). This concern is overdone in my view. Repeated consideration of these issues will result in arbitrators becoming adept at these issues. Further, arbitrators can seek advice from external experts.

The paper says that the negotiate-arbitrate approach is challenging for markets with high-frequency trading as it potentially leads to a large volume of arbitrations (4.25b). The OTC market for super peak and longer duration flexibility products are not particularly high frequency. However, if they become high frequency then participants will have a more informed basis for reaching agreement without arbitration and likewise arbitrators will have more information to quickly make arbitration decisions. Precedents will quickly be established, and the public database of contracts will become more relevant and robust, facilitating voluntary agreements.

5.2 The advantages of the proposed safe harbour

The optional safe harbour approach converts some cons into pros

The Options paper states the arbitration approach could be costly if used regularly, depending on the decisions needed (Tables 5 and 6, pp50-51). However, having the approach available as an option means gentailers will consider those costs when choosing the negotiate-arbitrate safe harbour. Gentailers will only choose to incur additional costs if the additional benefits exceed those costs. As the interests of non-integrated parties is protected by their right to appoint arbitrators (item 7 above), offering the negotiate-arbitrate approach as a safe harbour option will be welfare improving.

The paper states that an issue-by-issue arbitration process is likely to be slow and legalistic (Table 5, p50). These concerns are not so relevant when the arbitration approach is optional, because the arbitrator and negotiating parties have incentives to make the approach practicable and valuable. In my view, non-integrated parties are unlikely to gain great comfort from a set of high-level non-discrimination principles, giving gentailers considerable scope to interpret as they see fit. Concerns about uncertainty and information asymmetries apply under both approaches.

A safe harbour is sensible when considerable judgement is involved

The negotiate-arbitrate approach can be likened to common law. Arbitration decisions will be based on the facts of each negotiation, precedents will arise for dealing with difficult issues, and decisions will evolve as circumstances require. Arbitrations will provide clarity for all parties.

In contrast, relying solely on having non-discrimination obligations in the Code rests on the presumption that regulators have excellent foresight about what will work in hypothetical circumstances. If the high-level principles approach proposed by the Authority proves unsatisfactory, then long delays are likely before it is operating satisfactorily.

The Options paper states the negotiate-arbitrate approach would take longer to implement than the proposal (Table 5, p50). However, the more important issue is which approach will take longer to become effective. Given the divergence of views about how the wholesale and retail markets are performing, the wide scope for interpretation and the inherent information asymmetry, there is no grounds for confidence that adding new principles to the Code will be the end of the matter.

Allowing the negotiate-arbitrate approach as a safe harbour option reduces information asymmetry issues for the Authority. Arbitration decisions will provide information relevant for interpreting their high-level non-discrimination principles, assisting the Authority to specify more detailed guidelines or rules if it deems them necessary. If those rules work well, then gentailers will be more inclined to opt out of the safe harbour.

The negotiate-arbitrate approach is a targeted and proportionate option

The negotiate-arbitrate approach allows a more targeted approach because the contract-by-contract approach means it is easy to restrict it to a subset of OTC products. Item 4 restricts it to super peak products and longer duration flexibility products, which are the areas of concern identified by the Authority. The Authority could add peak products later if it becomes concerned about their availability and price.

The negotiate-arbitrate option is proportionate because the need for intervention (ie, arbitration) will be determined by industry participants on a case-by-case basis, rather than on a broad-sweeping rules-basis by the Authority.

The safe harbour approach is low risk for the Authority

As discussed in section 4, I am deeply concerned about the short-term retail price risks with the Authority's proposal. These derive from the requirement to benchmark implicit contract prices against market trades for comparable products and the prohibition on cross-subsidies. My level of concern depends, in part, on the specifics of that prohibition.

Making negotiate-arbitrate optional addresses the Authority's problem that it is unable to affirm that prices for super peak products are likely to be competitive. If arbitration reduces super peak prices sufficiently to address concerns about cross-subsidies, then 'all good'.[36] However, if it does not address those concerns, then allowing gentailers the negotiate-arbitrate option avoids "forcing" them to raise retail prices to remove cross subsidies. This avoids the risk of material short-term price rises for residential and commercial consumers.

5.3 Negotiate-arbitrate versus other options

If any gentailer elects the negotiate-arbitrate safe harbour, the operation of the regime would provide valuable information about its pros and cons before the Authority considered more intrusive options, such as step 2 in the Options paper. NIRs would be better placed to offer their views on the pros and cons, based on actual experience rather than hypotheticals. Arbitrators would also have valuable insights.

In my view, it is a 'no brainer' to provide a negotiate-arbitrate option as a safe harbour, as surely there is a non-negligible positive probability the Task Force will consider step 2. It would also assist with consideration of even more intrusive options, as discussed briefly below.

Negotiate-arbitrate vs mandatory market-making of super peak products

The negotiate-arbitrate approach is a few steps short of market-making arrangements. Both create incentives for competitive pricing. However, market-making is only suitable for standardised products, and incentives for competitive pricing depend on bid-offer spread obligations. The wider the spread, the weaker the incentive. In contrast, the wider the spread of bids and offers submitted to an arbitrator, the greater the value at-stake for both parties, so the greater the incentive to submit the most credible position.

A key disadvantage with market-making is that it is not a suitable safe harbour option, as no gentailer will provide market-making on a standardised product without other gentailers doing the same. However, if all gentailers indicate they would prefer to market make standardised super peak products, then the Task Force should consider this option rather than introduce non-discrimination obligations.

If market making was adopted for super peak products, the Task Force could retain negotiate-arbitrate for longer duration flexible products and exclude super peak products. Adopting the proposed safe harbour provides the Task Force with more information without restricting its future market-making options.

Negotiate-arbitrate vs mandatory supply of firming (MSOF)

Appendix D in the Options paper outlines the range of matters that would need to be decided if the MSOF option was introduced. It would clearly be costly and complex to design and operate.

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[36] Arbitrated contracts influence cross-subsidies through their influence on the prices agreed in negotiated OTC contracts. Arbitrage opportunities mean that prices for negotiated contracts influence prices for comparable market-traded contracts, against which implicit contract prices are to be benchmarked.

As with market-making, standardised firming products would need to be defined. The Options paper states that prices would be set by product buyers (if all bid prices exceed the reserve price) or by the regulator (who sets the reserve price). In fact, as the regulator specifies the offer quantity, it is in effect setting the market price even when the cleared price exceeds the reserve price.[37]

This carries significant price risks for parties required to offer the firming product, as they would not be directly involved in bargaining over prices. The problem for the supplier is that the regulator has no financial incentive to set the right quantities and reserve prices, and it would have minimal independent sources of information to do so.

In practice, the regulator would at times come under intense political pressure to set low reserve prices and large offer quantities, to reduce firming prices. Further, it would be heavily reliant on supply and contract information from gentailers, creating strong incentives for intense gentailer lobbying. In my view, the Task Force needs to carefully consider whether it is a good idea to create a regime with incentives for political and/or producer capture.

In contrast, the negotiate-arbitrate option "contracts out" the price determination decision to parties independent of the regulator. The plurality of arbitrators, and the bespoke nature of transaction-based decision-making, will make it far more difficult for politicians to put pressure on pricing. Further, both the bid and offer side of the negotiation have incentives to provide transaction-specific information.

Negotiate-arbitrate vs mandatory trading of gentailer hedges

Whereas Appendix D presented some detail about a possible MSOF regime, the matters outlined in Appendix C regarding mandatory trading of all gentailer hedges was scant. I would be surprised if it turned out to be significantly cheaper and easier to design and operate than MSOF.

6 Concluding comments

The above analysis argued the underlying problem facing NIRs is that they have poorer long-term price smoothing capabilities vis-a-vis incumbent gentailers. This was not important prior to 2018, as wholesale market prices varied over reasonably short cycles. However, the large and prolonged disturbance to the supply side of the wholesale market changed that.

For many years I have viewed the entry of NIRs as a contest between business models: a contest between gentailers with their large customer base and long-lived generation assets versus the nimbleness of new entrants with new technology and marketing ideas.

When I was a regulator, it was never a case of viewing one model as better than the other, or that the absence of one signalled the market wasn't working. It was up to the market to decide whether one model wins, or they coexist.

[37] This follows from standard microeconomics, that quantities are the dual of prices.

Appendix 1: Interpreting price-cost margins requires care[38]

The Options paper notes there is a large and ongoing gap between ASX hedge prices at Otahuhu and the LRMC of new baseload generation, as shown in Figure 4 on p30 of the Options paper. This appendix explains why the chart is comparing 'apples and oranges.'

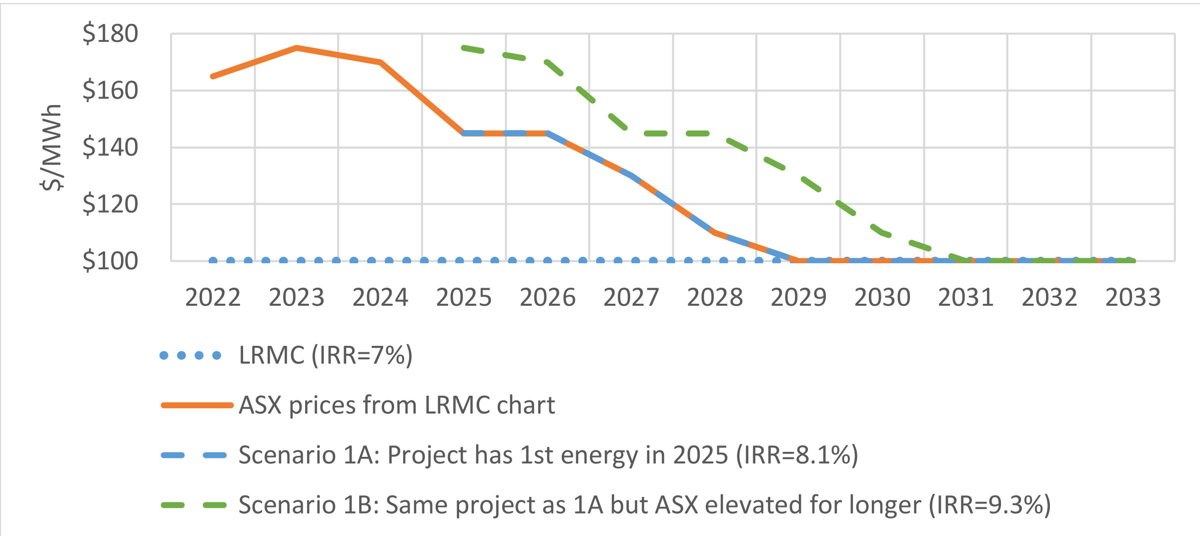
Suppose the LCOE of new baseload generation is $100.[39] LCOE includes a return on invested capital equal to the weighted average cost of capital facing investors. Suppose this is 7% per year. Projects with an internal rate of return (IRR) of 7% just 'wash their face', and their net present value is zero.

According to Figure 2 on page 10, hedge prices in 2020 were nearly $140, dropped to $120 in 2021, then jumped to $165 in 2022 and $175 in 2023. If sustained at this elevated level for the 25-year life of a solar plant, the plant's IRR would be 13.9% versus a 7% cost of capital. An exceptional IRR for generation investment, but this is a naïve scenario.

It takes about three years to find suitable property, design, consent, procure, and build solar farms. With spot prices expected to exceed LCOE in three years, investors are incentivised to act quickly to bring generation into the market in three years. They can be expected to continue doing so until hedge prices equal LCOE.

The orange line in Figure 9 mimics the ASX prices in the previous chart over 2022-2027, and from there, I assume prices fall to $110 in 2028 and equal LCOE from 2029 onwards. The dashed blue line (on the orange line) highlights the prices a plant receives if it produces energy by January 2025. The green dashed line is for an alternative scenario discussed later.

Figure 9: Price paths and IRRs for various investment scenarios



With hedge prices reaching $165 in 2022, suppose investors immediately began searching for a suitable property for a solar farm. Assuming a plant was operational three years later, at the start of 2025, it would earn revenue based on prices from January 2025 to

[38] The contents of this Appendix, apart from the last paragraph on the next page, were written in September 2024, hence assumptions about future hedge prices are outdated and not consistent with those in Appendix 2. However, the core message remains true.

[39] All prices and costs in this example are per MWh.

January 2050. In this case, the plant would earn an average price of $105.20 over its life and an IRR of 8.07%. This is Scenario 1A in the chart.

Consider a second scenario, where market prices remain elevated for two further years, perhaps due to gas and hydro shortages, before declining with the same pattern as for the orange line. As above, assume the project was started in 2022 and becomes operational in 2025. The project earns an average price of $111 and an IRR of 9.26%. This is Scenario 1B in the above chart.

Some investors may already own land suitable for a solar farm and battery and may have completed their design work. Suppose it takes them two years to procure and install their solar systems and connect the farm to the grid. Further, suppose they decided to invest in 2020, reacting to the $140 hedge prices in that year. Their first energy would be in January 2022, generating a 9.92% IRR if prices followed the orange path, as predicted in 2023.

Alternatively, suppose some parties invest in wind farms, which take at least six years from initial property selection to completion. Beginning their planning in 2020, they achieve first energy at the start of 2026. Under the orange price path, the wind farm earns an IRR of 7.60%. The following table summarises the IRRs in the above discussion.

Table 1: A wide range of IRRs are consistent with large price-cost margins

	Scenario A: ASX price path @ 2023	Scenario B: Delayed ASX price decline	Naive scenario: $175 ASX price
1. Solar project 1st energy 2025	8.07%	9.26%	13.90%
2. Solar project 1st energy 2022	9.92%		
3. Wind project 1st energy 2026	7.60%		

These calculations illustrate why three-year hedge prices should not be compared with 25-year cost estimates. A 75% price-cost margin in 2023 suggests an incredibly profitable opportunity, but that is misleading. The margins are far smaller when comparable timeframes are used for both prices and costs, as shown in Table 2 below.

Table 2: Price-cost margins when comparable timeframes are used

	Scenario A	Scenario B	Naive scenario
1. Solar project 1st energy 2025	5.2%	11.0%	75.0%
2. Solar project 1st energy 2022	13.6%		
3. Wind project 1st energy 2026	3.4%		

Charts like Figure 2 on p10 above (Figure 4 on p30 of the Options paper) should be accompanied by another chart (or a table) showing implied 25-year average prices so readers can compare prices and costs with comparable timeframes. Judgments are required to make comparisons, so high and low-price scenarios should be presented, as is done for LCOE. Alternatively, a table of IRR estimates could be presented for a suite of stylised scenarios.

Appendix 2: Estimated increases in household electricity prices

This appendix provides details on the calculations that underpin the figures reported in sections 4.1 and 4.2.

Composition of household electricity price

Let T denote the total household electricity bill, E the energy component and L the lines (transmission and distribution) component. Then T = E + L.

According to the quarterly retail sales (QRSS) measure of household electricity prices published by MBIE:

- T_{18}=29.14
- E_{18}=16.60
- L_{18}=12.54

where the subscript denotes the June 2018 quarter and prices are in cents per kWh.

Separating out generation

The Authority's website (https://www.ea.govt.nz/your-power/bill/) states that generation costs account for about 32% of the total household electricity bill. Letting G denote generation costs, G = 0.32 x T.

As E includes G, let A denote all other energy costs, ie, let A = E – G. Then T = G + A + L. Plugging in the above statistics gives G_{18} = 9.33 and A_{18} = 7.28.

From the QRSS, T_{24}=35.01, E_{24}=21.01 and L_{24}=13.99 in the December 2024 quarter. Define alpha as the generation share of the Energy Component in the June 2018 quarter. That is, let $\alpha \equiv G_{18}/E_{18}$ = 0.562.

The details so far are summarised in the table below. The beta parameter is used later below.

Table 3: Summary of data and key parameters

Key parameters					
G as a % of T	32.0%				
E_{18} as % of T_{18} (beta)	57.0%				
	T	E	L	G	A
2018 Q2	29.14	16.60	12.54	9.33	7.28
2024 Q4	35.01	21.01	13.99	11.20	9.81
% increase	20.1%	26.6%	11.6%	20.1%	34.8%

Hypothetical vs actual household prices for December 2024 quarter

Let G* denote the hypothetical value of G_{24} if escalating generation costs had been fully passed through to household electricity prices. Then the hypothetical total cost for households is $T^* = G^* + A_{24} + L_{24}$. For simplicity, assume the non-generation component of E is exogenous, that is, A_{24} equals 9.81 regardless of the value of G^*.[40]

If generation cost increases were passed onto households, and all other components of the electricity bill increased as they did in the QRSS, then residential electricity prices would increase by $(T^*/T_{24} – 1) \times 100$.

The following table shows the price impact for two scenarios. Scenario A uses the internal transfer price (ITP) Meridian reported to the Electricity Authority for the year ended June 2018/19 and an estimate of the ITP for the year ended June 2024/25.[41] Scenario B uses a simple average of ASX prices for long-dated electricity futures contracts at Benmore and Otahuhu, as of 2 July 2018 and 31 December 2024.

Table 4: Estimated short-term price increases

	Scenario A Meridian ITP	Scenario B ASX Average
2018 Q2	75.82	72.80
2024 Q4	150.24	157.91
% increase in G	98.2%	116.9%
G*	18.48	20.23
A_{24}	9.81	9.81
T*	42.28	44.03
Percentage by which T* exceeds T_{24}	20.8%	25.8%
Increase in household bill	$464.53	$576.24

Note: The ITP for 2024 Q4 is an estimate

These calculations suggest household electricity prices could rise by 21 – 26%.

How long before competitive pressure offsets the initial jump in prices?

Let $\beta \equiv E_{18}/T_{18} = 0.57$. This means $\%\Delta E = \%\Delta T/\beta$, allowing us to calculate an implied value of E under each scenario.[42] The table shows the number of years it would take to reduce E from E^* to E_{24} based on two scenarios for the effect of enhanced competitive pressure:

- 1.1% scenario – this is the rate at which the price of the energy component reduced in real terms over 2013-18, which was a period when retail entry and market share growth were particularly high.
- 2.2% scenario – this is simply twice the previous scenario, to consider the possibility that retail competition is far stronger than has occurred in the market to-date.

[40] Strictly speaking this share should be adjusted for the larger relative value of generation in 2024, however the unadjusted approach provides a reasonable first-order approximation to prices in 2024.

[41] I have estimated 2024Q4 ITP by escalating the 2023Q3 ITP by the half the rate at which the ASX Average increased over that period. The latter increased by 18.8%, so the escalator for the 2024Q4 ITP is 9.9%.

[42] We wish to consider a situation where ΔT is driven entirely by ΔE. That is, $\Delta E = \Delta T$. Then $\Delta E/T = \Delta T/T$, which means $\Delta E/E \times E/T = \Delta T/T$, which means $\%\Delta E \times \beta = \%\Delta T$, or $\%\Delta E = \%\Delta T/\beta$.

Table 5: Estimated time for initial price increase to be offset by competitive pressure

	Scenario A Meridian ITP	Scenario B ASX Average
Percentage by which T* exceeds T_{24}	20.8%	25.8%
Implied % change in E	36.5%	45.3%
Implied E*	28.68	30.52
Years to reach T_{24} for 1.1% scenario	28.1	33.76
Years to reach T_{24} for 2.2% scenario	14.0	16.8

The best-case outcome is that it would take around 14 years for enhanced competitive pressure to outweigh the effect of an initial increase in retail prices.[43] This is under the highly optimistic assumption that competitive pressure is double the strength that it was over 2013-18.

Number of years for break even if hedge prices revert to neutral prices after three years

The following table shows the additional expenditure households incur under the assumption that ASX prices are $137.50 for Year 1, declining to $87.45 for Year 4. This is the neutral price as T^* equals T_{24}, as shown in the right-hand-side column. The table shows that the additional spending over years 1 – 3 aggregates to just over $818.

Table 6: Estimated additional household expenditure

	Year 1	Year 2	Year 3	Year 4
2018 Q2 ASX price	72.80	72.80	72.80	72.80
Projected ASX price	137.50	120.82	104.13	87.45
% increase in G	88.9%	66.0%	43.1%	20.1%
G*	17.61	15.48	13.34	11.20
A_{24}	9.81	9.81	9.81	9.81
L_{24}	13.99	13.99	13.99	13.99
T*	41.42	39.28	37.14	35.01
Percentage by which T* exceeds T_{24}	18.3%	12.2%	6.1%	0.0%
Additional household bill	$409.36	$272.92	$136.48	$0.05
Total cost to consumer	$818.82			

Once ASX prices reach $87.45, competitive pressure is assumed to reduce household electricity spending by 2.2% per year (over and above other factors reducing household electricity bills, such as consumption efficiencies).

The following table shows the number of years it would take for households to save $818, to reach break-even.[44]

[43] Number of years = $\log(E_{24}/E^*)/\log(1\text{-}r)$, where r is the rate at which competitive pressure reduces real the price of the energy component. One scenario assumes r=-1.1% and the other assumes r=-2%.

[44] Number of years = $\log([P\text{-}S]/P)/\log(1\text{-}r)$, where r is the rate at which competitive pressure reduces the real price of the energy component.

Table 7: Estimated number of years to reach break-even

Total expenditure in 2024 from QRS	$2,343
Additional HH expenditure	$409.36
Year 1 HH expenditure (P)	$2,752.36
Savings goal (S)	$818.82
Competitive pressure effect on prices (r)	2.2%
Number of years to reach saving goal for 2.2% scenario	15.87

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Review of Level Playing Field Measures Options Paper

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May 6, 2025

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Contents

1. Introduction and Summary

1. In December 2023, the Electricity Authority (**EA**) commenced a Risk Management Review (the **RMR**) to better understand the competitive dynamics around risk management options for electricity retailers now and in the future. The EA undertook this review in the context of increasing demand for efficient risk management options led by growing wholesale market volatility and investment in intermittent generation. In addition, the EA was motivated by concerns raised by independent retailers about the availability and pricing of hedge products.
2. In November 2024, the EA released an issues paper with its findings (and re-affirmed these findings in its February 2025 update paper) which form the motivation for its Level Playing Field Measures options paper (**LPFM options paper**), which it released on 27 February 2025.
3. The LPFM options paper proposes to introduce a staged non-discrimination obligation, beginning with a principles-based approach and escalating to stronger/more prescriptive approaches if necessary.
4. We have been asked by Meridian to review the LPFM options paper, including:
   A. the proportionality of the interventions given the evidence relied upon;
   B. given the intervention has only been sketched out a relatively high level, the likely impacts and consequences of the intervention, depending on the way it is designed; and
   C. the relevance of references to the British experience of level playing field measures.
5. A summary of our findings is as follows:
   A. A key rationale for the proposed intervention is the EA's finding in the RMR that it could not conclude that prices for super-peak contracts were consistent with competitive prices. However, this analysis is necessarily *incomplete* rather than *inconclusive*. In particular, the EA recognises, but does not quantify, several legitimate reasons why super-peak contracts may be efficiently priced the way they are. An incomplete analysis of pricing does not justify the intervention proposed.
   B. A core function of wholesale electricity market participants is to provide risk management to one another, and to end-users of electricity. This is particularly true for energy retailers, whose core function it is to bundle and sell electricity to end-users at stable prices. Vertical integration in the electricity sector provides numerous risk management benefits in the form of underwriting generation and smoothing retail prices. This leads to more stable retail prices than could be delivered by non-integrated retailers.
   C. Vertical integration often emerges as a solution in markets where contracts are difficult or costly to write. In the case of electricity wholesale markets, this is because the implicit contract is an extremely fluid relationship between all of a gentailer's generation capacity and its retail book. Thus, any *explicit* contract between generators and retailers would not match the *implicit* contract between the generation and retail arms of a gentailer. If this contract could be easily specified, then there would be no need for vertical integration.
   D. While the intent of the EA's non-discrimination provisions is to make implicit contracts explicit and ensure independent retailers get the same deal as is available internally, the explicit contract will be by definition different from the current implicit contract. The proposed

obligations would effectively require forced internal contracting between the retail and wholesale arm on different terms than they implicitly do so now, which is in effect a form of virtual separation. In some ways, this intervention on gentailers' entire portfolios actually goes further than the targeted virtual disaggregation approach that the EA previously considered, which only related to certain assets.

E. The comparisons to telecommunications in the LPFM options paper are misplaced due to fundamental differences between the industries:

   i. Risk management is essentially an insurance product, which has very different characteristics from access to a physical telecommunications network.

   ii. The temporal nature of decisions to hedge commodity risk breaks the link between current forward looking risk management prices and retail prices, an issue that telecommunications access risk does not have to deal with.

   iii. Telecommunications access regimes generally do not have to deal with the scarcity and uncertainty of available capacity, as capacity generally follows the retail customer.

F. The proposed intervention could, depending on how it is implemented, result in retail prices becoming more volatile:

   i. Because gentailers smooth retail tariffs over the long term, the non-discrimination and no-cross subsidy requirements, if interpreted on the face of the description in the LPFM options paper (which could imply *currently offered* hedge prices will be used for assessing compliance with the no-subsidy requirement), will require gentailers to sell hedges at below market rates when wholesale prices are above long run averages (as doing otherwise would result in subsidy measured using the offered hedge prices).

   ii. To avoid the resulting arbitrage, this is likely to result in gentailers unwinding long run pricing smoothing and pricing to their retail businesses on a more short-term basis. This will result in consumers facing more volatile prices over time as retail tariffs will more closely track shorter run movements in wholesale and futures prices, to the detriment of end users.

G. Regarding the impact of the proposed interventions on investment incentives:

   i. If gentailers persist with long run retail pricing, and if the non-discrimination and cross-subsidy requirement are assessed using current offered forward rates, the resulting requirement to sell hedges at below market values will mean generators will not capture the full value of new investments they make in a flexible capacity. This will reduce the incentive to invest in this type of capacity.

   ii. If instead gentailers unwind long run retail price smoothing and retail prices become more volatile, this will result in gentailers having less revenue certainty. As the EA has described extensively in its paper on Power Purchase Agreements **(PPA),** revenue certainty provides many benefits for investment incentives, and few major generating investments are built without the backing of a PPA or vertical integration, both of which provide price stability.

   iii. The implication of the EA's proposal appears to be an outcome where some of the hedge capacity that is used internally by the gentailers today is contracted to Independent Retailers (**IRs**). As it is risky for small IRs to sign long term hedge contracts (due to uncertainty over their market share), this would mean that some proportion of capacity would be underwritten by shorter term contracts (compared to the implicit long term underwrite provided by vertical integration). This will increase revenue uncertainty for gentailers and similarly worsen investment incentives.

H. In the UK, policymakers have introduced a wide range of provisions to lower barriers to entry for independent retailers. However, the resulting pattern was a rapid growth in the number of retailers who adopted a short-term hedge strategy, followed by widespread collapse in recent years when prices increased. The costs of these collapses were socialised among all British energy customers. This experience highlights some of the risks of treating vertical integration as a bug rather than a feature of the system.

I. Our recommendations are therefore that:

   i. If a non-discrimination intervention is pursued, long term pricing smoothing at retail can be preserved if the non-discrimination and cross-subsidy rules are designed in a way that allows gentailers to sell hedges at market rates when prices are above long run averages. This would involve assessing the potential cross-subsidy against a historical book build of some description (where the historic book build involves purchasing hedge contracts at the prevailing market rates at the time).

   ii. Given that the EA's concern is around the pricing and availability of super-peak contracts, a much more directly targeted intervention would be mandatory market making for super-peak contracts.

2. Background

2.1. Evidence Relied on in Support of Intervention

6. In December 2023 the EA commenced the RMR to better understand the competitive dynamics around risk management options for electricity retailers now and in the future. The EA undertook this review in the context of increasing demand for efficient risk management options led by growing wholesale market volatility and investment in intermittent generation. In addition, the EA was motivated by concerns raised by independent retailers about the availability and pricing of hedge products.

7. In November 2024, the EA released an issues paper with its findings (and re-affirmed these findings in its February 2025 update paper), which form the motivation for its LPFM options paper.

8. The EA's key concern coming out of its RMR was around competition risks related to shaped hedges. This is of particular concern to the EA due to its finding that shaped risk management contracts would remain important for retailers in the short to medium term.

9. The EA's concern about competition risks related to shaped hedges is driven by two key concerns:

   A. the pricing of super-peak hedge contracts (the "**pricing concern**"); and

   B. retailers' access to shaped hedge contracts (the "**access concern**").

10. Regarding the ***pricing concern***, in the RMR the EA found that prices for baseload and peak OTC contracts were competitive. However, regarding super-peak contracts the EA states in the LPFM options paper that they:[1]

    > *…could not reach the same conclusion for OTC super-peak hedge contract prices as they trade at a substantial unquantified premium over ASX baseload prices adjusted for shape.*

11. The EA goes on to state:[2]

    > *Nor could we determine from evidence whether the prices of OTC super-peak hedges were consistent with competitive prices, and whether the increase in OTC super-peak prices (as a percentage of ASX baseload prices) that we observed over the assessment period is justified.*

12. This would initially appear to suggest that:

    A. The EA was able to estimate a competitive super-peak price that it considered was robust and accounted for all economically significant drivers of super-peak prices; and

    B. When it compared that robustly estimated competitive super-peak price to observed prices, the difference between them was both statistically and economically meaningful. In other words, the "gap" between estimated competitive prices and actual prices was large enough to raise competition concerns and also was not just statistical noise.

13. However, this is not the case as the EA was unable to make all of the adjustments that it considered necessary to estimate the competitive price of a super-peak contract. The EA's

1 Electricity Authority, Level Playing Field measures - Options paper: Energy Competition Task Force initiatives: Level playing field measures and prepare for virtual disaggregation of the flexible generation base, 27 February 2025, ("LPFM options paper"), para 3.39(f).

2 LPFM options paper para 3.39(h).

methodology involved starting from ASX baseload prices and then adding a number of premia, which it considered necessary for imputing a competitively priced OTC contract. In the table below we set out the different premiums the EA considered should be accounted for, whether the EA was able to account for that premium and the impact of not accounting for it.

14. As this table shows, of the six adjustments the EA considered necessary, it was only able to make two. Furthermore, as the table shows, the EA consistently notes that not making the adjustments means that the competitive price it has estimated is understated. By repeatedly understating the competitive price, the analysis is therefore biased towards finding that observed super-peak prices are greater than the estimated competitive price.

15. This would not be an issue if the four out of six premia the EA has not accounted for are unlikely to be material. However, this does not appear to be the case, with the EA noting in the RMR issues paper:[3]

> ***We have been unable to estimate other premia*** *(eg, premia for scarcity, volatility, and illiquidity)* ***that could have a big impact on super-peak contract prices*** *(and are likely increasing). [emphasis added]*

16. This point is made by the EA in support of the conclusion it reaches in the body of the RMR issues that:[4]

> *Offer prices for superpeak contracts could be consistent with a lack of competition, or simply reflect scarcity.*

17. This is an entirely reasonable description of the EA's analysis and findings – they do not know why super peak contracts are (seemingly) expensive. The issue in the present context is the framing in the LPFM issues paper mentioned in 10 and 11 above and the heading in the RMR issues paper that the EA "*can't rule out super-peak prices being non-competitive*" suggests that their analysis was *exhaustive but inconclusive*. By contrast the body of the report and the technical appendix correctly emphasise instead that the analysis is *incomplete* due to the complexities involved in doing it properly.

18. In other words, if the EA were able to add all the relevant premiums, given they "could have a big impact", it is possible the "substantial unquantified premium" would disappear. Of course, they also might not. We simply do not know why super-peak prices are at the level they are.

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[3] Electricity Authority, Reviewing risk management options for electricity retailers – issues paper - Chapter 5: Availability and pricing of OTC contracts, 7 November 2024 ("RMR Issues Paper – Chapter 5"), para 2.7(c).

[4] RMR Issues Paper – Chapter 5, para 2.7.

Table 2.1: Premiums the EA considers must be added ASX baseload prices to impute competitive super-peak prices

Premium	Description	Included?
Location	ASX prices are only available for Benmore and Otahuhu. Therefore contracts at other nodes require an adjustment to account for differences in price levels between the node in question and the BEN/OTA node.	**Yes.** Adjustment made based on historic average differences in nodal spot prices.
Shape	Prices in super-peak periods are higher than baseload prices, so a shape premium is added to account for higher prices in these periods.	**Yes.** Adjustment based on historical average differences between spot prices in super-peak and baseload periods. In practice, this shape premium will probably increase as spot prices become more volatile.
Illiquidity	OTC contracts are less liquid than ASX contracts and therefore sellers would require a premium.	**No.** *"While **we think there should be an additional premium added to reflect lower liquidity in the OTC market** (compared to the ASX market), given the complexities involved in doing so (including estimating liquidity of the OTC market relative to the ASX market, and then translating this into an additional $/MWh figure), we have not attempted to do so here. We note however that **our estimated competitive OTC prices will therefore likely be underestimated.**"*[5] *[emphasis added]*
Spot price volatility	Volatility means retailers are willing to pay a premium to insure against high prices. The EA finds that at super-peak times, there is less likelihood of low prices and more likelihood of very high prices.[6]	**No.** *"Again, due to the complexities involved, we have not attempted to estimate this premium, and therefore **our estimate of competitive contract prices is a lower bound.**" [emphasis added]*
Scarcity	In super-peak periods, energy and capacity are more likely to be scarce, which increases the likelihood that the gentailers will be short on generation these periods.[7] We understand this to be that if gentailers sell hedges but are short on generation, they are exposed to the spot price in these periods and therefore will require a premium to account for this risk.	**No.** *"We decided against adding this premium to our estimated contract prices due to the complexities involved in estimating such a premium, and because some of this scarcity will be captured in the ASX premium. But it must be considered when comparing our estimated competitive contract prices to actual OTC prices that **a lot of the time (especially due to current scarcity in the market) we will be underestimating contract prices.**"*[8] *[emphasis added]*
ASX volatility	Because gentailers often back the OTC contracts they sell with purchases on the ASX, they are exposed to the risk of ASX prices changing between when they price up and offer a contract and when it is accepted (which is the point at which the backing ASX trade would actually be made).	**No.** *"We did not attempt to add this premium to our estimated competitive contract prices due to the uncertainty involved in the calculation and in keeping with not adding other premia."*[9]

5 Electricity Authority, Reviewing risk management options for electricity retailers – issues paper - Appendix A: How we calculate competitive risk management prices, 7 November 2024, ("RMR Issues Paper – Appendix A"), para 4.11.

6 RMR Issues Paper – Appendix A, para 4.14.

7 RMR Issues Paper – Appendix A, para 4.17.

8 RMR Issues Paper – Appendix A, para 4.18.

9 RMR Issues Paper – Appendix A, para 4.21.

19. Regarding the ***access concern***, the EA found that while retailers to date have been able to secure substantial shaped hedge cover through OTC contracts, the market for shaped cover is neither deep nor liquid. The EA bases this conclusion on its findings that:[10]

A. Over a third of the time retailers receive only one offer in response to requests for shaped hedges.

B. Around half of all requests resulted in a trade.

C. Around a third of all offers received were for less volume than requested.

D. Super-peak contract requests received fewer offers per request than baseload and peak, receiving at least one conforming offer around half the time.

E. All offers received for super-peak contract requests were from gentailers (no other participant types responded to such requests).

20. However, the EA also finds that:

A. Almost all requests (over 99 per cent) received at least one offer.

B. Not many participants are able to respond to super-peak requests (usually three at most).

C. Evidence points to fuel or capacity scarcity often being the driver behind the current thin and illiquid market for shaped hedge cover. Indeed, the EA hypothesises that the lower response rates and conforming bids in the most recent data (Q1 and Q2 2024) may have been affected by the energy scarcity in 2024.

21. While the evidence points to scarcity being a driver of its access concern, the EA does not rule out that there is a plausible driver with competition implications (i.e., refusing to supply products on appropriate terms to counterparties who are downstream competitors), indicating that some level of market power *could* have been in play.

22. In addition, even if there were evidence that anticompetitive behaviour was occurring, the EA's own analysis from the RMR suggests that this would not be competitively significant given:

A. The EA finds that pricing of baseload and peak contracts is competitive; and

B. The EA's modelling of the risk reduction benefits of different portfolios found that a portfolio of baseload, peak and super-peak hedges is similar to a portfolio of baseload and peak hedges.[11]

23. Given the uncertainty of the nature and scale of the drivers of these concerns, the EA should ensure that any interventions are appropriately targeted and proportionate, and thus do not create unintended consequences that may exacerbate the problems they seek to solve.

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10 RMR Issues Paper – Chapter 5, pp.7-9.

11 RMR Issues Paper – Chapter 4, para 5.14.

2.2. The EA's Proposals on Non-Discrimination

24. As a solution to its pricing and access concerns, the EA proposes three fundamental requirements:

A. **Non-discrimination (ND) obligation:** The EA's guidance on its proposed non-discrimination principles is that gentailers are required to deal with all buyers "*on substantially the same price and non-price terms and conditions […] as those made available (either expressly or implicitly) to: (a) the gentailer's internal business units; (b) other buyers*."[12] The EA highlights that one of the key concerns from independent retailers is that "*Gentailer approaches to pricing hedge contracts for those retailers appear to be discriminatory compared to their internal pricing*."[13]

B. **Forward-looking internal transfer pricing:** The EA further proposes to require that gentailers "*establish an economically meaningful portfolio of internal transfer prices in a form able to be used to demonstrate compliance with the non-discrimination principles […] based on observable market rates for comparable risk management contracts*."[14] The EA further suggests in a footnote that "*ITPs could be strengthened to ensure that they: (i) are representative of Gentailers' retail price setting practices, and (ii) represent the current cost of buying wholesale electricity (rather than in some cases being backward looking)*."[15]

C. **No cross-subsidy obligation:** The EA lastly "*considers that any cross-subsidy […] that results in an internal business unit not being commercially viable on a standalone basis would breach the non-discrimination principles*."[16] In short, a cross-subsidy would appear if the retail arm's revenues (from tariffs) were below its costs, including its implicit internal transfer costs.

25. In Q&A with the EA, they have further clarified that:[17]

A. The non-discrimination obligations will only be triggered when the generation arm offers a hedge product to the retail arm;

B. While the EA recognises that currently there may be no explicit hedge contracts between the retail and generation arm, the intent of the proposals is "*make the implicit, explicit.*" This will occur by requiring the gentailers to establish a notional hedge book between the retail and wholesale arm.

26. The ND and non-subsidy requirements are on their face quite simple. However, both leave a lot to be interpreted, particularly in the context in which gentailers offer stable retail prices based on the long-term stability of their integrated portfolio. For example:

A. For the ND requirement, it is not clear whether it would be sufficient to show non-discrimination on a:

i. *backward-looking basis:* i.e. that the gentailer would have to offer hedges that are consistent with the gentailer's hedged cost of electricity as delivered on that same day.

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12 LPFM options paper, Appendix B, para 12.

13 LPFM options paper, para 6.20

14 LPFM options paper, Appendix B, para 15.

15 LPFM options paper, fn 57.

16 LPFM options paper, Appendix B, para 17.

17 Meeting between Meridian and the EA on 3 April.

This would mean that the offered hedge price would reflect the historical book build of a retailer over the years leading up to that delivery date; or

ii. *forward-looking basis:* i.e. that the gentailer would have to offer hedges consistent with its current internal transfer price, or with market rates, to be delivered in the future. However, the gentailer would still be allowed to *deliver* power on that day based on a historical set of notional internal transfers that an independent retailer would not have access to. The EA suggests that this is how the non-discrimination clause should be interpreted ("*non-discrimination does not mean that a hedge sold today would be priced the same as a hedge sold a year ago*"[18]), but there is ambiguity on this point, particularly given the EA's description of the no cross-subsidy requirement.

B. For the cross-subsidy requirement, it is not clear whether the cross-subsidy would compare tariffs to a long-term hedging strategy, or to the current/recent forward price, and over what time frames those would be measured, e.g. whether each business unit would have to be commercially viable as assessed over the course of a financial year or over some longer period.

27. As we discuss in Chapter 4, there are important implications for how these requirements are interpreted.

[18] LPFM options paper, para 6.10(b)

3. Economic Theory of Hedging in the Electricity Sector

3.1. The Role of Risk Management in Electricity Markets

28. The wholesale electricity market is based on the ongoing provision of electricity in real time, from generators to retailers (and ultimately to customers via retail markets). The wholesale market includes both a physical and a financial component.

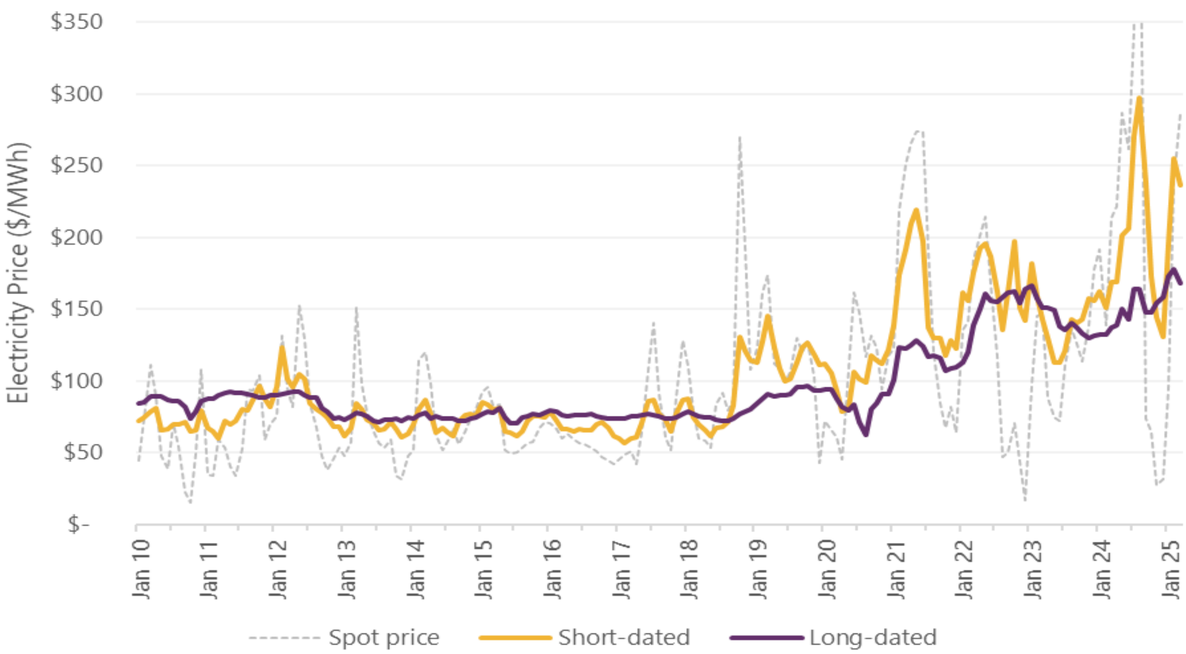
29. In the physical component, generators offer to produce electricity at a certain price and every half hour, the system operator matches supply to demand, and calculates the price at which they match. This price is then paid by all users who receive electricity, and received by all generators who are called to produce electricity.

30. Especially as driven by supply-side conditions, the price of electricity from one period to the next can be very volatile: e.g. if there is a surplus of wind and hydro power available (as determined by nature), then the price could be very low; if there is a shortage of wind power and hydro power, then the price could be very high.

31. For this reason, financial markets exist. For example, a retailer and a generator could enter into a swap contract, guaranteeing a price at a certain level. The generator and retailer would still sell into the physical market but would agree to settle the difference between the physical price and the swap strike price. Figure 3.1 below demonstrates the volatility of wholesale prices and how this can be mitigated to different extents by different hedging strategies.

32. This figure shows average prices for short-dated hedges (those for delivery within one year) and long-dated hedges (those for delivery beyond one year) and the seven-day moving average of the spot price. This demonstrates that long-dated hedges are much less volatile than the short-dated hedges and the seven-day moving average spot price.

Figure 3.1: Volatility and Price Level of Different Hedge Maturities and Spot Prices



Source: EA Energy Market Information portal, available at https://www.emi.ea.govt.nz

33. As an alternative to contractual arrangements, this kind of arrangement could exist implicitly within a vertically integrated gentailer. Vertical integration provides a "natural" hedge because a sale by the generation arm is purchased by the retail arm and therefore the two offset each other. In this situation, because purchases and sales offset, there is no explicit price for matched sales.

34. Fundamentally, generators provide three services that are directly valued in the wholesale (physical and financial) market:

    A. Production of bulk electricity, i.e. the MWh of electricity that are ultimately consumed by end users. The value of this is effectively captured in the price of baseload power, or in PPAs.

    B. Production of flexible or firming electricity, i.e. electricity that can be relied upon to produce when capacity is scarce. The value of this is effectively captured through the price of power during peak hours, or from peak contracts in the hedge markets.

    C. Risk management to retailers. As we discuss below, the wholesale spot market can be very volatile, so the reliable supply of electricity at a stable price provides a value to a retailer that offers its customers a stable retail price of electricity.

35. On the other side, retailers also provide three services:

    A. Act as an intermediary between smaller customers and the wholesale market, and ultimately bundle wholesale, transmission, and distribution costs into a single bill. While some large industrial users may engage directly in the wholesale market, most end users are not sophisticated enough to do this.

    B. Retailers provide innovative products to end users. For example, a retailer could offer a retail tariff which passes through the spot market price, or an app that notifies the user of their consumption patterns, or special EV rates, etc.

    C. Most importantly, retailers provide risk management, to their users and to generators. Because of the volatility in the physical market, retailers act as an important counterparty to generators, guaranteeing them stable revenues even if the physical market conditions fluctuate. On the other side, retailers typically offer their own customers a stable retail rate, ensuring that the customers are not exposed to wild fluctuations in energy prices, which would be difficult to budget for on a household level. Where the retailer has physical assets of its own, it is able to better withstand fluctuations in the power price, even if those assets are not necessarily generating at the same time and acting as a natural hedge. Thus, the fundamental role of a retailer is to provide risk management services to customers at the lowest possible cost.

36. In the options paper, the EA highlights concerns from independent retailers regarding vertical integration:[19]

    > *The efficiencies that can be derived by the gentailers from vertical integration seem almost entirely financial or risk management based, rather than productive efficiencies, and we urge the EA to properly consider the competitive effects and optimal market design without placing undue weight on unquantified and ill-defined vertical efficiencies.*

37. The implication seems to be that if the efficiencies from vertical integration are financial or risk management based they are not real efficiencies, or should be given less credence than "productive" efficiencies. However, as we set out above, a core role of generators and retailers in

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[19] LPFM options paper, para 3.18.

electricity markets is managing risk. Indeed, the whole premise of the proposed interventions and independent retailers concerns is that shaped hedges (a form of risk management) are a critical input for independent retailers to be able to compete.

38. It would therefore be incorrect to downplay any efficiencies from vertical integration in electricity markets on the basis they are financial or risk management based, given these efficiencies relate to one of the core functions of electricity markets.

39. In addition, the scope for "productive efficiencies" on the retail side is limited to billing and other customer interface functions, which collectively are likely a very small part of the cost of retail electricity sales, compared to wholesale procurement and network charges. On the retail side at least, productive efficiencies should therefore be of lesser concern than efficiencies related to risk management.

40. In the rest of this chapter, we outline the economics of vertical integration and the efficiencies that can result from it in an electricity markets context.

3.2. Economics of Vertical Integration

41. Vertical integration is not unique to electricity markets. Firms vertically integrate in many competitive markets as an efficient and competitive response to market imperfections. Most of the reasons why firms choose to vertically integrate have to do with reducing costs or eliminating a market failure.[20]

42. The key type of costs that firms aim to eliminate through vertical integration are transaction costs. Transaction costs are the costs associated with writing and enforcing contracts such as searching for a seller or buyer, agreeing to contract terms, monitoring performance and contract obligations, and enforcing the contract (including managing and financing credit control). These costs are often substantial, making contracting a potentially expensive way to coordinate different activities within a supply chain.

43. Among other reasons, contracts can be particularly costly to write if they involve specialised assets and uncertainty.[21] When a firm requires specialised assets, it may face costs resulting from the absence of a competitive market for their specific need. Hence, firms may struggle to acquire the optimal asset or may be dependent on a firm who produces the specialised asset, exposing them to potential exploitation in the short run (i.e., the firm may be "held up" by their supplier).[22]

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20 However, vertical integration can be costly in its own right. For example: (i) The cost of supplying its own factors of production or distributing its own product may be higher for a firm that vertically integrates than for one that depends on competitive markets, which serve these needs efficiently. (ii) As a firm gets larger, the difficulty and cost of managing it increase. The advantage of dealing with a competitive market is that someone else supervises production. (iii) The firm may face substantial legal fees to arrange to merge with another firm. Carlton and Perloff, Modern Industrial Organization – Fourth Edition: Pearson, 2015, ("Modern Industrial Organization"), p.421-422.

21 Contracts involving the supply of information and extensive coordination can also be particularly costly and lead to vertical integration. Modern Industrial Organization p.425

22 Vertical integration can be the best solution to the hold-up problem. Holmstrom and Roberts, "The Boundaries of the Firm Revisited", *Journal of Economic Perspectives*, Vol.12, no.4, 1998, pp.73-94, p.74.Transaction costs of specialised assets discussed in: Modern Industrial Organization p.425-426.

44. In a world with uncertainty, it can be difficult and costly to negotiate a contract of the right length that deals with all possible contingencies.[23] Hence, prices can be effectively higher as a result. If a firm signs a contract that is too short, it will be subject to additional costs from returning to market and writing a new contract.[24] On the other hand, if a firm signs a contract that is too long, it may face termination costs, or be stuck with a contract that no longer fits its needs, or with terms that become unfavourable as market conditions change. Prices may also be higher overall under uncertainty if, for example, the counterparty requires a risk premium to compensate it for the uncertainty.[25] By vertically integrating, firms can guarantee that the asset will meet their exact needs while avoiding the hold-up problem and higher effective prices in the process.

45. Another common reason why firms vertically integrate is to assure the supply of important inputs. Assurance of supply is important in markets where price is not the sole device used to allocate goods.[26] If a firm cannot guarantee a stable and timely supply of an important input it can be difficult to remain viable. Therefore, if the important input is scarce or being rationed so that there is not sufficient supply to meet market demand, firms have an incentive to vertically integrate to raise the probability of obtaining the input.

3.3. Benefits of Vertical Integration to Electricity Market Participants

46. As discussed in Section 3.1, electricity generators and retailers face price and quantity risks that arise from volatile spot prices, uncertain generator output, and uncertain customer demand. Since price risk affects generators and retailers in opposite directions, they can manage the risk by signing a swap hedge contract to fix the price at a certain level. However, signing such a contract can involve substantial transaction costs and little flexibility to respond to changing market conditions. In addition, electricity market participants cannot assure a supply of contracts that will meet their risk management needs.

47. Since the risk management requirements of electricity market participants involve specialised assets and uncertainty, the transaction costs of signing hedge contracts can be high. Each electricity market participant faces unique conditions and needs. For instance, firms often face different locational spot prices, generation risks, required generation times, and optimal contract length. As a result, it can be difficult and costly to find a counterparty and to design a contract that meets both parties' requirements (no hedge contract is one size fits all). Firms therefore often maintain a portfolio of contracts with different counterparties to replicate a contract that meets their needs.

48. However, maintaining a portfolio of contracts is a costly undertaking that requires ongoing management and negotiation.[27] Furthermore, since spot prices are volatile and uncertain, contract buyers are charged a premium to compensate the seller for risk. For OTC peak and superpeak

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[23] Modern Industrial Organization p.29.

[24] As noted by Coase a key motivation for a longer contract is to avoid these costs. Coase, R. H, "The Nature of the Firm," *Economica*, 4, 386, 1937, p.4.

[25] This is particularly the case for financial contracts. In finance, it is fundamental for investors to seek a risk premium above the risk-free return to compensate for the uncertainty and risk associated with their investments.

[26] Modern Industrial Organization p.427.

[27] ACCC, Retail Electricity Pricing Inquiry: Final report, June 2018, p.123.

contracts, these premiums can include an illiquidity premium, spot price volatility premium, scarcity premium, and an ASX volatility premium.[28] By vertically integrating, firms can manage their risk through an internal hedge which allows them to avoid the transaction costs from signing hedge contracts.[29]

49. Moreover, fixed price and quantity contracts will not manage the quantity risk faced by electricity market participants. In fact, signing contracts with fixed prices and quantities may even increase quantity risk, because they are then committed in advance to that quantity level. Option contracts can help manage risk, but it may be costly to find a form of option contract that suits more than one market participant relative to the cost of managing uncertain outputs within a vertically integrated firm.[30] While vertical integration may not remove quantity risk, it can reduce it by giving vertically integrated firms more flexibility to respond to changing market conditions. As noted by the ACCC (citing NERA):[31]

> *In essence, the ability to increase or decrease generation output facilitates a more flexible hedge against the retailer's change in demand. This flexibility is difficult to achieve through contracts, which typically specify a fixed volume.*

50. Finally, electricity market participants cannot guarantee a steady supply of hedge contracts that fully meet their risk management needs. While there are standard ASX hedge contracts and alternatives to hedges contracts like batteries and demand response, these may not fulfil the needs of all firms. Contracting OTC is also not guaranteed since it relies on there being a firm with opposite needs/risks to facilitate a deal. If generators cannot appropriately manage their risk, they may not achieve the investment grade credit rating required for the construction of new generation. On the other hand, if retailers cannot appropriately manage their risk, their businesses may become financially unviable due to the fixed price contracts they sign with their consumers.

51. Therefore, by reducing transaction costs, providing firms with flexible risk management through an internal hedge, and assuring that their risk management needs are met, vertical integration can be a more efficient way for electricity market participants to manage wholesale electricity market risk.

3.4. The Value of Vertical Integration to Consumers

52. Despite the preconception by some competition and regulatory authorities, there is very little evidence that vertical integration has a negative effect on competition and consumer welfare. In their review of the empirical literature, Lafontaine and Slade find that in general, vertical integration in competitive markets is beneficial to both firms and consumers, and that imposing restrictions on vertical integration is usually detrimental to consumers. Hence, the authors conclude that the burden of evidence should be on the regulator to demonstrate harm before imposing restrictions on vertical integration.[32]

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28 RMR Issues Paper – Appendix A.

29 We note that most vertically integrated firms in the electricity market still participate in contracting markets to some degree, so these transaction costs are not necessarily entirely avoided.

30 NERA, International Experience of Vertical Integration in the Electricity Sector - A Report for AGL Energy Ltd, 22 November 2017, p.5.

31 ACCC, *Retail Electricity Pricing Inquiry: Final report*, June 2018, p.123.

32 Lafontaine and Slade, "Vertical Integration and Firm Boundaries: The Evidence", *Journal of Economic Literature*, Vol. XLV, September 2007, pp.629-685, p.680

> *[U]nder most circumstances, profit– maximizing vertical–integration and merger decisions are efficient, not just from the firms' but also from the consumers' points of view. Although there are isolated studies that contradict this claim, the vast majority support it. Moreover, even in industries that are highly concentrated so that horizontal considerations assume substantial importance, the net effect of vertical integration appears to be positive in many instances. We therefore conclude that, faced with a vertical arrangement, the burden of evidence should be placed on competition authorities to demonstrate that that arrangement is harmful before the practice is attacked. Furthermore, we have found clear evidence that restrictions on vertical integration that are imposed, often by local authorities, on owners of retail networks are usually detrimental to consumers. Given the weight of the evidence, it behooves government agencies to reconsider the validity of such restrictions.*

53. In electricity markets specifically, vertical integration can provide value to the consumers of electricity in several ways, including by:

    A. Decreasing generators' incentives to exercise market power, which can result in a decrease in retail prices;

    B. Increasing the stability of retailers, which can assure stable retail prices; and

    C. Facilitating the construction of new generation which is essential to maintain the reliability of the grid and can lead to lower retail prices.

3.4.1. Decreasing Incentives to Exercise Market Power

54. Vertical integration can decrease retail prices by decreasing generators' incentives to exercise market power. In their theoretical model of the New Zealand electricity market, Hogan and Meade find that retail prices are higher with vertical separation than balanced vertical integration.[33] Frontier's empirical study on the effect of vertical integration on bidding behaviour in the Australian National Electricity Market (**NEM**) supports this by finding that vertically integrated generators typically bid more competitively than stand-alone generators:[34]

> *[V]ertically integrated generators in fact behave more competitively on average than when they were operating as stand-alone generators. The vertically integrated generators were found to be bidding 4 to 6 percentage points more capacity at competitive prices. This statistically significant, robust, and striking result is contrary to claims that vertically integrated generators will bid at higher prices than stand-alone generators.*

55. These findings align with economic theory. When vertical integration is the efficient response to underlying conditions in electricity markets, it creates firms that can offer generation and retailing services at a lower cost than two standalone firms integrated through contracts (as discussed in Section 3.3). Hence, in a competitive market, competition among vertically integrated firms can drive prices down to a level that would be impossible without vertical integration.

56. A vertically integrated firm should also have less incentive than an unhedged standalone generator to exercise market power due to the natural hedge that is created through vertical integration.

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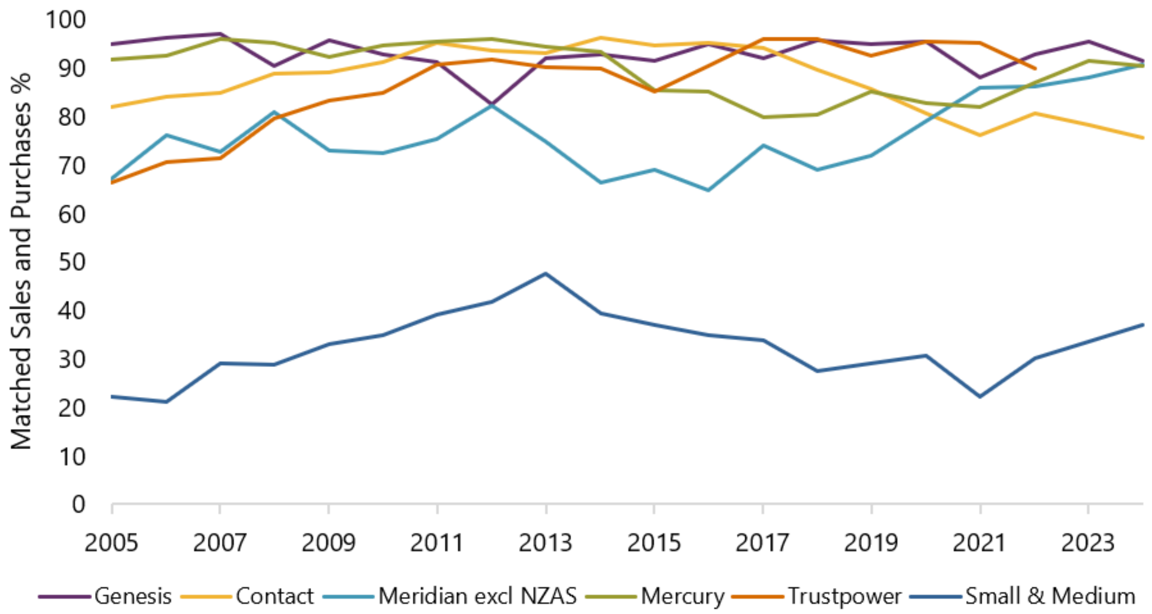
33 Balanced vertical integration meaning that the firms' retail and generation shares are roughly equal. The larger the generator share relative to the retail share, the lesser the effect. Hogan and Meade, "Vertical Integration and Market Power in Electricity Markets", New Zealand Institute for the Study of Competition and Regulation Working Paper, 18 February 2007.

34 Frontier Economics, Effects of vertical integration on capacity bidding behaviour: A Report Prepared For Herbert Smith Freehills, August 2017, ("Frontier, Effects of Vertical Integration"), para 12.

This is because a gain that the generator component of a vertically integrated firm makes from selling at a higher spot price will be at least partially balanced by a loss from the retail component of buying at the higher spot price. Therefore, if a large standalone generator vertically integrates with a retailer, its incentive to exercise market power should significantly decrease, if the merging parties are of similar scale in terms of MWh sold in wholesale and retail markets.

57. This finding is dependent on the standalone generator being more hedged after the merger than before. However, this should usually be the case as hedge contract markets are imperfect and generators typically acquire larger retailers for the purpose of risk management. Indeed, Frontier notes that one of the reasons for their finding is that generators in the NEM were generally more naturally hedged after the vertical merger than they were financially hedged before the vertical merger.[35] The vertically integrated "gentailers" in New Zealand also have broadly balanced portfolios of generation and retail sales as demonstrated by Figure 3.2 below, so it is likely that they would be less hedged (like the small & medium non VI firms) and therefore have a greater incentive to exercise market power if they were not vertically integrated. The figure below only represents the extent to which firms are naturally hedged (i.e., it excludes financial hedges), hence, it understates the full degree to which these firms are hedged.

Figure 3.2: Extent to which energy sales and purchases match by firm (yearly)



Notes: EA defines metric with the following. If a firm or trader has total purchases that precisely equal its total sales, then sales and purchases are matched. If total purchases exceed total sales then only a portion of the trader's purchases are matched by its sales, and vice versa. If S denotes sales and P denotes purchases, the matched volume is equal to min(S, P). The VI measures expressed as a percentage, whether volume or value, are defined as: 100·2·min(S, P)/(S + P). Positions in derivative markets and other financial hedging arrangements are not included.
Source: NERA analysis of Electricity Authority EMI vertical integration trends data, available at https://www.emi.ea.govt.nz

58. Another reason why vertically integrated generators should act more competitively is because, unlike standalone generators who know precisely their contracted positions, vertically integrated generators' position for a given trading period is uncertain (because retail load is not known until

35 Frontier, Effects of Vertical Integration, para 57.

usually after the trading period). Therefore, vertically integrated generators should act more conservatively and bid more capacity at lower prices.[36]

3.4.2. Assuring Stable Retail Prices

59. Incumbent gentailers have a very stable book, largely from internal hedges, which are implicit over the life of the generating asset. As a result, retail prices tend to be very stable, reflecting a long lag of energy supply that has been internally procured over the preceding years. This implicit relationship is necessarily complex, representing the fluctuating real-time relationship between generation output and retail sales, over many years. It cannot be represented in a simple set of hedges that can be explicitly procured on an exchange.

60. A recent empirical study by Gibbard et al. focuses on costs pass through in the New Zealand retail electricity market.[37] They find that, while independent and vertically integrated retailers pass through similar fractions of lines costs, independent retailers pass through significantly more of their generation costs (measured using the price of futures contracts) compared to integrated retailers. The authors state that the asymmetry in what the futures cost represent for integrated and independent retailers may explain the difference in generation cost passthroughs:

> *On the one hand, for independent firms, the futures cost corresponds to a monetary expense of acquiring generation. On the other hand, for an integrated retailer whose generation covers their retail supply, the monetary expense of generation is the cost of producing electricity — including the cost of maintenance, inputs and equipment.* ***For such an integrated retailer, the futures cost does not represent a monetary expense of generation but, arguably, it represents an opportunity cost of using its generation to supply its own retail entity****. [emphasis added]*

61. By having lower passthrough for generation costs, the authors note that this may lead to vertically integrated retailers having more stable retail prices:

> *… consider the effect of a positive shock to the generation costs facing retailers: as independent retailers are imperfectly hedged, they may need to pass on, to some degree, the rise in generation costs, whereas integrated firms may be insulated from the shock, to the extent that they enjoy a natural hedge.*

62. As we show in Figure 3.3 below, the tariffs offered by retailers more closely track the longer run hedge prices, if a conservative approach to hedging was taken. The graph below uses the EA forward curve data and computes the delivery year price using the futures prices for that delivery year and taking the unweighted average of all prices. Given ASX futures prices begin trading 3 years out from the delivery date, this is equivalent to assuming a retailer buys a futures contract for a given delivery year every day for the 3 years leading up to that delivery period. We understand that this is broadly how Meridian and other gentailers construct their ITPs, though their actual implicit internal hedges are longer term and more complex.

63. Comparing this to retail price tariffs (as published by MBIE) shows that retail tariffs have been relatively smooth, with there being periods of "overs" and "unders" where retail prices have grown by more or less than this measure of the long-run hedged book build cost. As the graph shows, since 2022, even on the 3-year long run hedging strategy we present here, we are currently in a

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[36] Frontier, Effects of Vertical Integration, para 58.

[37] Gibbard, P., C. Grubb & D. Wesselbaum. "Cost pass-through in the retail electricity market: Vertically integrated versus independent retailers" Energy Economics, Vol.145, 2025.

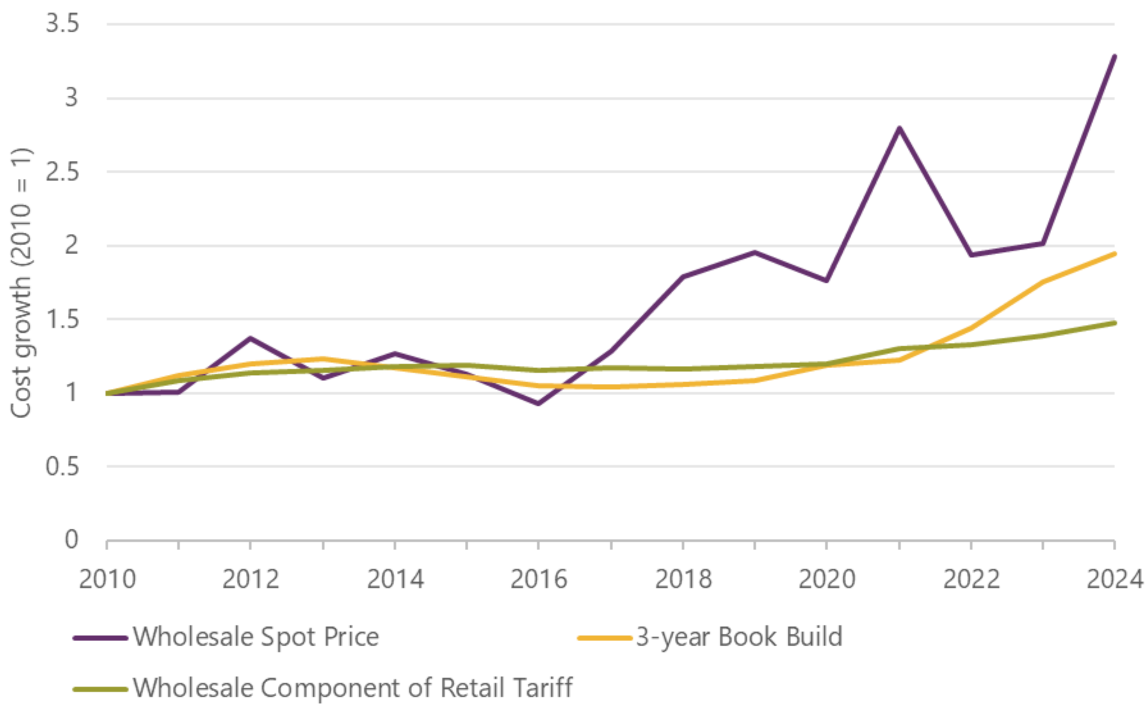
period of under-recovery, whereby wholesale costs have been increasing at a substantially greater rate than retail prices. This may be because the 3-year book build measure understates the extent and duration of implicit hedging.

64. By contrast, we have also overlaid the average wholesale spot price, which is much more volatile than either and has grown at a substantially higher rate than retail tariffs or the long run hedged book build cost in recent years.

65. Therefore, a retailer that does not hedge as much, or is hedged over a shorter duration will necessarily have more volatile retail pricing, allowing them to grow their customer base in times of low prices.

66. If a retailer is less hedged, then the tariffs it would need to offer would rise more quickly in the recent years, simply as a result of its hedging strategy. This is to some extent inevitable – in order to build market share, independent retailers often adopt a shorter hedge strategy to achieve cheaper prices, but are then more exposed to upward market fluctuations later.

Figure 3.3: Tariff Growth has been Slow and Stable Compared to Apparent Wholesale Costs



Source: NERA analysis of EA Energy Market Information portal and MBIE residential electricity cost data, available at https://www.emi.ea.govt.nz and https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-statistics/energy-prices/electricity-cost-and-price-monitoring

3.4.3. Facilitating the Construction of New Generation

67. Consumers benefit from investment in generation for several reasons. First, without these investments, a power grid would not exist. Additionally, increasing generation capacity enhances the reliability of the electricity system and helps reduce the retail prices that consumers pay.

68. Since the build of new generation capacity is extremely capital intensive, firms' ability to attract financing and the cost of this financing plays a significant role in determining whether they can

invest in new generation. In energy-only markets like the New Zealand electricity market and the NEM, new plant requires the involvement of an investment-grade credit rated entity either as a principal investor or underwriter of long-dated PPAs.[38] This is no surprise considering that the finance for large new generation capacity can take 20-30 years to pay back. Hence, stable firms are required in electricity markets to facilitate investment in new generation (either as builder of new generation or as the writer of PPAs).

69. Relative to independent generators and retailers, vertically integrated firms are more stable due to the reduction in transaction costs and efficient natural hedge created through the firm structure. In their paper on vertical integration in the NEM, Simshauser et al. find that pure-play generators and retailers are unable to consistently sustain investment grade credit metrics whereas vertically integrated firms can, even despite the wild commodity price cycle in their data set.[39]

> *Our model results reveal that vertical re-integration restored financial stability and earnings predictability to isolated merchant business combinations in the NEM's energy-only market. In theory, shareholders of such business combinations could achieve this diversification through separate holdings, but crucially, the theory assumes perfect capital markets. We explicitly relaxed this assumption in our modelling and found integration to be very important. Investment-grade credit and its associated efficiency could only be sustained in the long run by purposefully altering the vertical boundaries of merchant firms.*
>
> *The modelling results were clear. Vertical[ly-integrated] Retailers were capable of obtaining and sustaining investment grade credit ratings, and Pure Play businesses could not. Further, vertical firms could write a 'bankable' PPA and based on the quantitative results, would have the capacity to execute equity and debt capital raisings at what we would describe as the efficient level, whereas Pure Play businesses could not.*

70. Hence, as the EA notes, vertically integrated gentailers can achieve low-cost access to capital and a competitive levelised cost of electricity.[40]

71. Independent firms can attempt to replicate the effect of a natural hedge through PPAs, however, the ability of PPAs to deliver low capital costs depends on the credit strength of PPA buyers.[41] In addition, it is not possible to match a natural hedge with contracting, since it would be a function

[38] Simshauser et al., "Vertical integration in energy-only electricity markets", *Economic Analysis and Policy*, Vol 48, December 2015, pp.34-56, p.36.

The EA reinforces this in its recent working paper on PPAs. International investors expect that a PPA will be in place to secure long-term revenue for new generation projects (based on their experience in other jurisdictions). However, the ability of PPAs to deliver low capital costs depends on the credit strength of PPA buyers.

Electricity Authority, Entrant generators – context, headwinds and options for power purchase agreements: Working paper, paras 3.12(d), 4.27(a).

[39] Simshauser et al., "Vertical integration in energy-only electricity markets", *Economic Analysis and Policy*, Vol 48, December 2015, pp.34-56, pp.51-52.

[40] Electricity Authority, Entrant generators – context, headwinds and options for power purchase agreements: Working paper, paras. 4.27(b).

Levelised cost of energy compares lifetime costs and generation output across different technologies. In general, a lower LCOE is more attractive for developers as, on average, the asset can pay itself back with lower average electricity prices. https://www.ea.govt.nz/news/eye-on-electricity/the-levelised-cost-of-electricity/

[41] Electricity Authority, Entrant generators – context, headwinds and options for power purchase agreements: Working paper, paras. 4.27(a).

of the retailer's tariffs, the generator's production cost, and the wholesale price, all of which are not static.

72. Therefore, through their ability to access capital at a low cost and write PPAs, vertically integrated firms can play an important role in facilitating the construction of new generation which is essential to maintaining the reliability of the grid and keeping prices low for consumers.

4. Characterisation of the Proposed Intervention

4.1. The EA's Proposals Border on Virtual Disaggregation

73. The fundamental proposed non-discrimination measure is the requirement for gentailers to make available to independent retailers what they make available for themselves internally. In order to do this, the EA would require explicit record-keeping obligations. For example, the EA would require gentailers to establish "*an economically meaningful portfolio of internal transfer prices based on market traded hedges adjusted for internal requirements,*"[42] which would then need to be available to trade with independent parties. In other words, the requirement is to make the gentailer's implicit contract explicit, and then make it available.

74. In practice, it is not possible for a gentailer to build its implicit contract using market traded hedges, without changing the implicit contract itself. This is because the implicit contract is based on a very complicated relationship between the cost of its assets over their remaining lives, its long-term expectation of its customer base and expected retail tariff levels, the flexible nature of its generation fleet and customer base (e.g. demand side response), climate conditions, the known and unknown shape of demand, etc. Resolving this complexity implicitly is one of the benefits of vertical integration, as we describe in Section 3.3.

75. Given the long-term and fluctuating nature of this implicit hedge, it would not be possible to exactly replicate that strategy with standard-traded hedge products, which are only available on the ASX up to three years in advance, or are sporadically (and privately) traded over-the-counter over longer horizons.

76. Instead, to comply with this requirement, gentailers would actually need to *change* their hedging strategy, and this would essentially require gentailers to implicitly purchase what they *could* explicitly purchase from public hedge markets.

77. As mentioned in Section 2.2, the EA has stated that the ND obligation would only be triggered when a gentailer offers a hedge to its retail arm, with the implication that some capacity could be held back for own use. However, it is not clear how this would occur in practice, as it seems the EA would require the gentailers to make offers to themselves through the establishment of the portfolio of ITPs and the establishment of an initial hedge book, the latter of which the EA acknowledges "will have relatively long-lasting implications."[43]

78. At its core, this requirement to establish explicit internal arrangements is not fundamentally different from virtual disaggregation, which the EA describes but does not propose in the first instance. In the EA's description of the virtual disaggregation option, gentailers would be required to offer (internally and externally) a specified number of firming contracts based on the gentailer's flexible capacity.[44]

79. On one hand, the EA's requirement for the gentailer to essentially hedge based on what could be procured on markets would be more extreme than its targeted virtual disaggregation proposal, because it would cover the whole portfolio rather than be tied to specific assets. On the other

42 LPFM options paper, para 6.19.

43 LPFM options paper, para 6.51.

44 LPFM options paper, Appendix D, para D.16.

hand, the gentailers would still save on transactions costs because they would not have to *actually* trade those hedges for the internal proportion of trade, but would for the external part.

4.2. Differences between Electricity and Telecommunications

80. At various places the EA makes reference to the telecommunications sector as precedent for the interventions it is proposing, though it rightly recognises that care should be taken when making comparisons between sectors.[45] This is particularly the case when comparing generators providing risk management products to telecommunications companies providing access to the physical telecommunications network.

81. While it is correct that non-discrimination obligations and access regulation is common in telecommunications markets with vertically integrated incumbents, the context is different.

82. In fixed broadband, where these obligations commonly apply, there is no uncertainty over of the quantity available of the upstream input. If a non-integrated retailer wins a retail customer, the upstream network owner must provide access to that customer on the same terms as it is implicitly supplying itself.[46] Similarly, given the costs are comprised of an already constructed physical network and some active network equipment (with the former being the majority of the costs),[47] the cost of providing access is not particularly volatile. It is thus relatively straightforward to define the terms of access and what non-discrimination means in a situation where quantity does not need to be rationed and costs are not very volatile.

83. By contrast, regarding access to risk management in electricity, the quantity of risk management available is uncertain (in New Zealand, available hydro storage is a key driver) and its price is volatile, since it reflects expectations of future wholesale prices. Because risk management is a form of insurance, it is often purchased well in advance of when electricity needs to be delivered, which can result in a disconnect between retail prices and the current cost of insurance.

84. In other words, access regulation for electricity risk management needs to deal with issues that telecommunications does not (uncertainty of quantity, price volatility and consequently a temporal disconnect between retail prices and the input price). Providing insurance and a telecommunications network are substantially different products. This is not changed by the fact that insurance in the electricity sector is provided by large physical assets – it is still a financial product, as opposed to the provision of physical access as occurs in the telecommunications context.

85. Particular care is therefore required when applying telecommunications access pricing logic to electricity risk management. While the EA does acknowledge the need for this care, in practice it draws conclusions and parallels between the industries that cannot be supported, due to the inherent differences between them. This is because:

   A. The temporal disconnect between retail prices and current risk management prices complicates determining whether there are any subsidies; and

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45 E.g. at paragraphs 3.2 and 4.19 of the LPFM options paper.

46 We note that in New Zealand telecommunications regulation, this is the concept of equivalence of inputs (EOI), which appears to be broadly what the EA is referring to when it discusses non-discrimination.

47 Note that active equipment is only supplied by the incumbent if access sought to an "active" service, rather than to "dark fibre".

B. Uncertainty and scarcity of risk management volumes means that the access regime can directly determine market structure, by determining how capacity is rationed.

5. The EA's Proposals May Produce Unstable Retail Prices

86. While the EA's proposed non-discrimination provisions could be viewed as a simple means of promoting competition, they have the potential to bring a wide range of unintended consequences that would be detrimental to New Zealand energy consumers. In particular, these provisions may create a world in which gentailers no longer offer stable prices which come from a long-term hedging strategy. This has negative consequences for customers and generators alike.

5.1. The EA's Requirements May Be Internally Inconsistent

87. As we describe in Section 2.2, there are three fundamental requirements that the EA proposes which may not be compatible with one another, depending on how they are interpreted:

A. **Non-discrimination obligation:** i.e. that gentailers are required to deal with all buyers on substantially the same terms;

B. **Forward-looking internal transfer pricing:** i.e. that gentailers are required to explicitly measure and publicise an internal transfer price based on current market conditions; and

C. **No cross-subsidy obligation:** i.e. that gentailers' retail arms should be commercially viable on a standalone basis, with revenues greater than costs (as measured by the new internal transfer price that the EA would require gentailers to define).

88. The LPFM options paper does not specify explicitly whether these implicit internal transfer costs used to measure cross-subsidy must be the same as the forward-looking ITPs used to measure compliance with the non-discrimination obligation.

89. As described in Section 3.4, gentailers currently take a long-term approach to retail pricing as they implicitly have very long-term hedges through owning long lived assets. When wholesale prices rise, as seen in spot and futures markets, these gentailers are often slow to increase their retail prices, because they have implicitly (and in cases where they are short, explicitly) hedged much of their retail requirements from previous periods when prices were lower. In other words, retail prices substantially lag current spot and forward prices and therefore the ITPs the EA proposes the gentailers establish.

90. There are two broad approaches that could be adopted to assessing the no-subsidy requirement:

A. **Assess retail profitability using *current* offered forward rates:** This would measure whether the gentailer's retail tariffs would be profitable for a standalone retailer which has not made any historical purchases of risk management products, and therefore would need to purchase them immediately on the current forward markets.

B. **Assess retail profitability using a historic book build:** This would measure whether the gentailer's retail tariffs would be profitable for a retailer that had adopted a long-term approach to risk management by hedging well in advance of the delivery period, given historical ASX prices and current retail tariffs.

91. Since gentailers have historically taken a long-term approach to retail pricing, these two approaches to measuring the no-subsidy requirement will yield very different results in times of rising prices, even if the gentailer sells hedges to independent retailers at current market rates.

92. In the present situation where there is long-term price smoothing and a lag between retail tariffs and spot/forward prices, the no-subsidy requirement would be violated if it is measured against the current forward rates. This is because retail tariffs reflect historic hedging decisions based on a longer-term hedging strategy. Thus, retailing would be unprofitable for a retailer that has only hedged short-term when forward prices are currently higher than they have been in the preceding few years.

93. In this situation, there are only two ways the gentailer could satisfy the no-subsidy requirements:

A. **Offer hedges at below market rates:** This would involve offering hedges to independent retailers on the basis of the hedged cost from a long-term hedging strategy. However, this would be loss making in times of rising wholesale prices, because the hedge would be forward-looking while the implicit hedge cost is based on historical hedge prices, possibly over several preceding years. In this situation, selling at the historical cost would allow buyers of these contracts (primarily independent retailers, but possibly also financial traders) to arbitrage the gentailers by immediately selling the hedge on the ASX at higher prices. It would even be optimal for the retailer to actually not serve any retail customers, because they could costlessly arbitrage between the gentailers and the ASX without the obligation of actually delivering energy. The end result in this case would be a wealth transfer to these independent retailers from gentailers who sell below-market hedges and from customers who see a reduction in retail competition. The options paper mentions that the non-discrimination requirement is not a "most favoured nation clause," but a current/as-offered approach to assessing the no-subsidy requirement would turn it into one.

B. **Adopt a retail pricing strategy based on a shorter-term hedging strategy:** In order to avoid the arbitrage that would result from offering hedges to retailers at below the current forward looking price, gentailers could change their retail strategy to set retail tariffs that more closely track current spot and near term futures prices. Doing so would mean that selling hedges at current market rates would be unlikely to violate the no-subsidy principle. As we discuss in the next section, this would mean retail prices would be more volatile and higher in times of rising prices and lower in times of falling prices.

94. Given the first approach would result in material arbitrage, if the no-subsidy rule is assessed based on current offered forward prices, the rational response of the gentailers would be to unwind the current approach to long run price smoothing and price on a more short-term basis. This second strategy would satisfy the no-subsidy rule, but would mean that gentailers' retail customers would no longer benefit from the tariff stability offered by a long-term hedging strategy, as we now discuss.

5.2. Consumer Tariffs May Become More Volatile if Hedging Becomes More Short Term

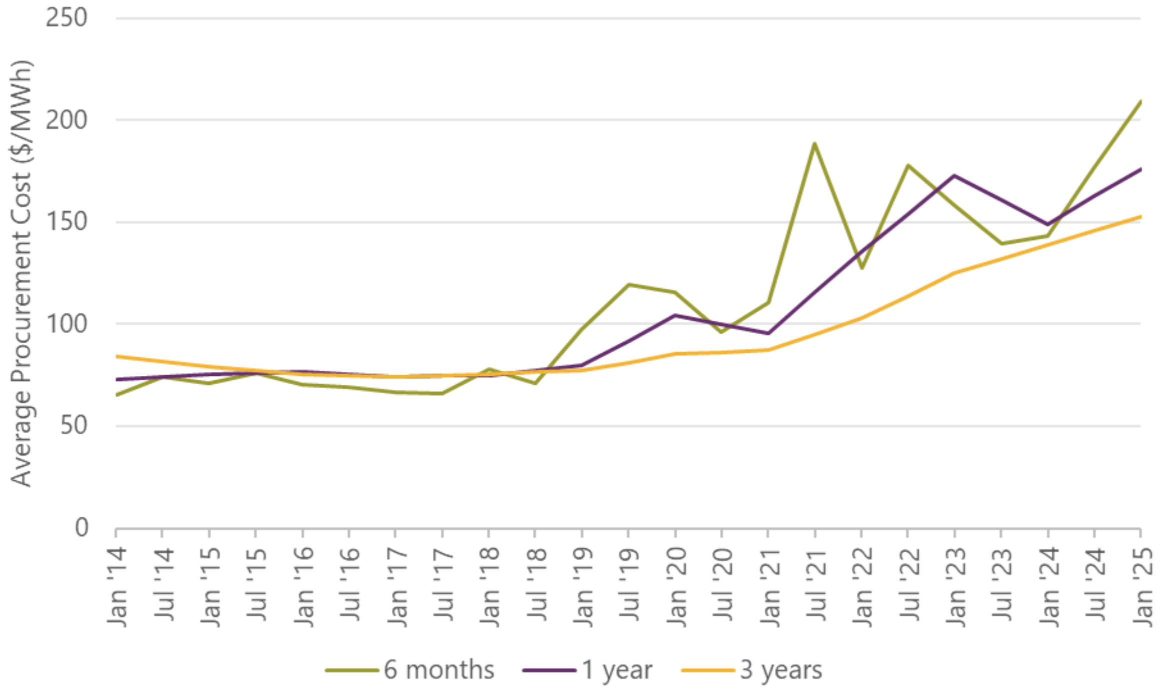
95. The EA's proposals could force gentailers into a retail tariff strategy based on a shorter-term hedging strategy or current forward-looking hedge prices over a short horizon, either of which would result in more volatile tariffs. This volatility can be illustrated in a few ways, using data published in the EMI portal.

96. First, we can show the impact of setting retail prices based on a short-term book build by examining the impact of the length of the book build on the hedged cost of electricity for a given

delivery year. The EA publishes prices for different delivery years, as traded on individual dates in previous years. For example, a retailer that adopts a long-term book build hedging strategy (or implicitly, a gentailer) might purchase contracts for delivery in the 2024 calendar year over the three preceding calendar years, while one that adopts a short-term hedging strategy might purchase them over the one preceding calendar year, or even the six months prior.

97. In Figure 5.1 below, we show how the average hedged price for each delivery year varies depending on the length of the hedging strategy used to procure it, taking the average price for delivery in each calendar year as traded over every trading day in the six months prior to the year, one year prior to the year it, or the three years preceding it.

Figure 5.1: Average Hedged Price by Hedge Strategy



Notes: For data availability purposes, for the six-month contract, we assume that the retailer purchases "short-dated" hedges (a blend of hedges up to 12 months forward) every day up to the beginning of a new six-month period, at which point it updates its tariffs.
Source: NERA analysis of forward price curve data from EA, on average between Otahuhu and Benmore, available at https://www.emi.ea.govt.nz

98. There are two important patterns to note in this figure:

A. First, when the price outlook increased beginning in 2019, the short-term hedge strategies immediately produced an increase in average price in 2020 (and beyond). The long-term hedge strategy shows only a minor increase in 2020, because the average price is 67 per cent composed of trades in 2017-18, before the price outlook increased. While the long-term hedge strategy does show increases in the average price paid throughout the 2020s, these lag behind those of the short-term hedge strategies. This suggests that a retailer adopting a longer-term hedge strategy would be able to offer lower retailer prices than one adopting a shorter-term hedge during this period. Of course, during times of *falling* prices, the opposite would be true and shorter-term hedging strategies would support lower prices.

B. Second, the longer-term strategy yields more stable prices. The shorter-term strategies show large fluctuations from each year to the next, but the longer-term strategy only shows increases in price when driven by a sustained trend. A retailer with a shorter-term hedging strategy would need to either pass on those large fluctuations in costs to customers or have sufficient financial stability to absorb that volatility internally.

99. For customers who are sensitive to shocks in their energy bills (e.g. for budgeting purposes), access to a tariff based on a long-term hedging strategy provides stability and value that other tariff bases do not. The EA's proposals risk taking this kind of tariff off the table, though this could be avoided depending on how the terms of the non-discrimination and no-subsidy requirements are defined.

100. In particular, if the no-subsidy requirement is clarified to reflect a historical book build, gentailers could retain their current approach to retail pricing. However, this would create a difference between the hedge cost the gentailer has incurred through its hypothetical book build process and the current price it is offering for hedge contracts. This may fall foul of the non-discrimination requirement, depending on the EA's application of it.

101. To resolve this, the EA should clarify its definition and application of the cross-subsidy requirement. Optimally, in a rising market, a gentailer should be allowed to offer independent retailers hedges close to market rates (as seen on ASX), while also allowing its own customers to benefit from their historic hedging decisions. In these cases, an independent retailer would only be able to underprice the gentailer if (a) it had adopted a similarly safe hedge strategy; and (b) it is able to outperform the gentailer on other costs (which are minimal) or innovation.

6. Implications for Investment Incentives

102. As we describe in Chapter 5, the EA's proposals risk creating volatile retail prices. Additionally, while the EA intends for them to improve investment conditions, they risk instead dampening investment signals, both on their own and via their impact on retail prices. The precise avenue for this impact depends on (a) how the EA ultimately interprets the requirements; and (b) how market participants respond to them.

6.1. The Provisions Could Force Gentailers to Accept Below-Market Prices for Risk Management

103. First, if gentailers are required to sell hedge contracts at the price of their own concurrent internal transfers, and they do not take a forward-looking approach to doing so (hence maintaining stable retail prices), then gentailers would receive below-market compensation on these hedges during times of rising prices. This is because the implicit internal pricing would be based on historical prices when prices were lower.

104. Periods of high prices are the times when risk management products are most valuable and in many cases the periods upon which a business case will be premised (for example, batteries and other flexible plant). As a result, if gentailers are required to sell risk management products at below market rates during these periods, they would not capture the full value of that risk management product, which they rely upon to support their substantial upfront investment costs.

105. Furthermore, when a gentailer builds a *flexible* asset, like a gas or hydro storage plant, they do so in part to protect the retail arm from price volatility, i.e. to better match its internal hedge. The EA proposes that gentailers "*would no longer be able to prioritise allocation of available shaped hedges to their own retail functions as they are currently able to. Instead, they would be required to make those hedges available to all potential buyers*".[48] If a gentailer is not able to fully use its flexible generation to offset risk for its retail arm, and does not capture the full value of the insurance it provides because it is forced to sell at below market value to other firms, then this takes away a substantial portion of the value of building it, and hence reduces the incentive to build it.

106. These times of higher prices may be seen as generator upside that is not actually required to justify the investment, which could have been supported on the lower prices seen historically. However, there are several reasons why this is not the case:

    A. Investments are made with some expectation of price variation (particularly flexible plants). Any ceiling that artificially applies on hedge prices would reduce the expected return on any investment. When an investor chooses to build a new plant, they do so based on the expectation of energy market revenues over the life of the plant, which will include some periods of higher prices and some periods of lower prices.[49] If the periods of higher prices are truncated artificially, then this necessarily reduces the expected market revenues from the point of deciding to make the investment, and the investor will be less inclined to carry out the investment.

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48 LPFM options paper, para 6.40.

49 In the current context where gentailers will be selling hedges to independent retailers, this means periods of selling higher priced hedges and periods of selling lower priced hedges.

B. The requirement to sell below-market hedges is one-sided. In times of falling prices, when the internal transfer price is above-market, the gentailer could offer above-market hedges, but independent retailers would buy cheaper hedges from the ASX instead, or on the spot market. Therefore, the gentailers would essentially have to offer at-market prices in those periods or not sell any risk management products externally. Additionally, during *falling* prices, gentailers may lose retail market share as independent retailers are able to undercut them with a shorter-term hedging strategy, so they may have reduced ability to sell internally.

C. Futures prices may be rising because costs are increasing in a way that affects the gentailer. For example, the more recent volatility in prices in New Zealand is driven in large part by uncertainty in gas conditions, as well as uncertain hydrological conditions. Where a gentailer owns these technologies, then increased future prices are partly reflective of their own increased *costs*, and the gentailer would require those higher revenues in order to offset the higher cost.

D. Given the mismatch between the hedge prices offered by the gentailer and those concurrently available on the ASX, independent retailers may arbitrage by buying cheap hedges from the gentailer and on-selling them, meaning that gentailers could be forced to sell a much larger quantity of below-market hedges than would be required to actually satisfy their demand.

107. If gentailers do not capture the full value of their investments in risk management because it is artificially underpriced, they will have a reduced incentive to invest in it, artificially below the value that those investments can provide to the market.

108. This issue falls away if the provisions are interpreted in a way that would allow selling risk management at current market rates, while also continuing to set retail prices on a book-build basis.

6.2. More Volatile Retail Prices Increases Risk for Developing Generation by Gentailers

109. If the gentailers instead react to the provisions by adopting a shorter-term/forward-looking approach to setting retail prices, then those retail prices will be more volatile, as we establish in Chapter 5. Aside from the negative effect this could have on retail customers, this tariff volatility represents revenue volatility for the gentailer, to the extent to which it is internally hedged.

110. First, assume that a gentailer is perfectly hedged internally, both in volumes and shapes. In this case, every MWh produced in its generators would be consumed by its own retail customers, and it would not need to participate in wholesale markets at all.

111. For this hypothetical gentailer (which does not exist in reality), any investment in generation would be paid for exclusively by retail electricity sales, with no exposure to wholesale market volatility. Thus, the only revenue volatility to the gentailer would be driven by retail revenues, i.e. retail price times retail volume.

112. If instead the retail arm adopts a volatile, forward-looking pricing strategy in order to comply with the EA's provisions, then the generation investments will be supported by volatile retail revenues, which is a less reliable basis (compared to a smooth long term price path) to support investment in heavy infrastructure with a long pay-back period.

113. The consequences of less stable revenues on investability are well-documented by the EA in its recent working paper on PPAs.[50] The EA highlights the following among reasons why a developer of renewable energy would wish to enter a PPA:

A. **Remove revenue volatility**, as relying on spot revenues would produce earnings which could vary substantially from month-to-month and year-to-year;

B. **Remove revenue uncertainty**, mitigating longer-term price uncertainty that could arise from system conditions like hydrology;

C. **Improve access to financing**. These more stable and predictable revenues "gives lenders and investors confidence", which "can flow through to reduced financing costs".[51] Considering the high capital costs of a generator, these financing benefits lead to materially lower costs, which can be passed through to consumers through lower tariffs.

114. The EA's discussion relates to renewable energy generators selling PPAs, but all of these same conclusions are equally applicable to developers of other forms of generation, and to internal hedging as a way of ensuring revenue stability.

115. Of course, no gentailer is perfectly hedged internally, as described in Section 3.3. Even if a gentailer produced the same number of MWh that it sold to retailers, it is highly unlikely that these would happen at the same time. Furthermore, if a gentailer were perfectly hedged and then built a new generator, they would then be in a net long position and would still have a need to sell some hedges to ensure revenue stability. However, to the extent that a gentailer is hedged internally, it relies on stable retail prices to support that hedge, and more volatile retail prices would harm investment conditions accordingly, increasing the cost of capital and hence the final costs to customers.

6.3. Generators Typically Rely on Long-term Offtakers to Support Investment

116. In general, large infrastructure projects like energy generators have long pay-back periods and therefore require reliable revenues to underwrite them. Around the world, generation capacity has largely come from:

A. **Government ownership.** For example, in most of the world in the 20th century (including New Zealand), and in most developing countries today, the power sector was owned by a public sector entity, which is responsible for ensuring an adequate supply to the country's population. Because demographic trends are typically slow moving, the entity can plan new plant with relative certainty knowing that (a) the customer base (i.e. the population) will be not so different from forecasts in 20-30 years; and (b) compensation from state budgets (depending on the precise institutional arrangements) will be available. Much of Western Europe, as well as Australia and New Zealand, have privatised their energy sectors, but still operate assets which were built during the period of public ownership.

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50 EA, Entrant generators – context, headwinds and options for power purchase agreements – Working paper, January 2025.

51 EA, Entrant generators – context, headwinds and options for power purchase agreements – Working paper, January 2025, para 3.12

B. **Government underwriting.** This is common in countries that have since liberalised their energy sectors but require large investments that the market will not deliver for various reasons. For example, in order to procure large-scale firm renewable energy projects, Australia operates the Capacity Investment Scheme (CIS), which guarantees eligible developers at least 90 per cent of their target revenue, through top-ups above energy market revenues.[52] In the UK, when policymakers have decided that there is a strategic interest in new nuclear capacity, they have compensated the developers through a fixed payment per unit of output over a long period of time. This is the case for Hinkley Point C, currently under construction by Électricité de France (EDF), which will receive a guaranteed strike price of £92.50/MWh (in real 2012 terms) for its first 35 years of operation.[53]

C. **Long-term PPAs.** In a PPA, a single buyer agrees to purchase output from a generator at a fixed price. Generally these are "generation-following" PPAs, in which the buyer buys power whenever it is generated. The EA's current working paper on PPAs identifies 13 PPAs in New Zealand, nine of which have a corporation as the offtaker (e.g. Amazon), and all but one of which has a term of 10-20 years.[54]

D. **Incumbent vertically-integrated utilities.** We describe the role of vertical integration in underwriting generation investment in Chapter 3.

117. What these all have in common is that the counterparty is reliable over 10 or more years, virtually guaranteeing the generator predictable revenues over the large portion of the life of the asset, and thus giving investors sufficient certainty to invest.

118. Independent retailers are unlikely to contract on similar terms, given that they are less likely to have a stable customer base that can be predicted several years in advance. Instead, they typically target shorter hedges which allow them flexibility to serve their customer bases.

119. If some portion of a gentailer's hedge capacity is contracted on these shorter terms demanded by independent retailers, instead of being implicitly underwritten on a long-term basis through vertical integration, then it will limit the extent that the generator has a reliable, long-term counterparty for its output, increasing the cost of capital and ultimately increasing costs borne by electricity customers.

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52 See https://www.dcceew.gov.au/energy/renewable/capacity-investment-scheme and Australian Government, Capacity Investment Scheme - Market Brief on Capacity Investment Scheme - National Electricity Market – Generation Tender 1, May 2024, p.19.

53 https://www.theguardian.com/news/2017/dec/21/hinkley-point-c-dreadful-deal-behind-worlds-most-expensive-power-plant

54 EA, Entrant generators – context, headwinds and options for power purchase agreements – Working paper, January 2025, Table 4.1.

7. British Experience of Retail Market Regulation

120. As Chapter 2 explains, the EA proposes to implement non-discrimination obligations to address perceived market power concerns over independent retailers' access to super-peak hedge contracts.[55] The EA believes that ensuring retailers have access to risk management contracts will facilitate the entry and growth of independent retailers, which it argues will benefit consumers by providing more choice and putting downward pressure on prices.[56]

121. This chapter reviews the recent history of the retail energy market in Great Britain, whose regulator, Ofgem, pursued policies that promoted the entry and growth of small, independent retailers with the aim of improving outcomes for customers.[57] While Ofgem succeeded in increasing the number of retailers in the industry to 70 retailers by 2018, 65 retailers have exited the industry since 2018, imposing costs of at least £9.1 billion on consumers.[58]

122. Ofgem also found that its regulatory environment contributed to the extent of failures by enabling retailers to enter with insufficient capital and pursue excessively risky business models to target growth.[59] In particular, Ofgem identified that many of the failed retailers adopted short-term hedging strategies that left them exposed to wholesale price volatility.[60]

123. While there are differences in market structure with New Zealand, the case study provides important lessons for policymakers of retail markets:

A. Availability of hedging products is correlated to higher retailer entry, but at a cost to the parties mandated to make products available.

B. Without regulatory oversight, new entrant retailers have incentives to adopt risky strategies to compete on price with incumbents following long-term hedging strategies.

C. Fixating on retailer entry without ensuring sustainability in new entrant business models may end up creating more costs for customers than the benefits of competition and innovation that new entrants may drive.

7.1. Ofgem Implemented Policies That Reduced the Costs of Entry for Small Retailers

124. Following the privatisation of the British gas and electricity industry, the 14 regional Public Electricity Suppliers ultimately merged to form six retailers by 2006, which represented 99 per cent of the domestic electricity and gas market collectively known as the "Big Six".[61] These companies

[55] LPFM options paper, pp.14-15.

[56] LPFM options paper pp.2, 13.

[57] Ofgem, The development of a competition framework for the domestic retail market, August 2023, p. 2.

[58] This included the cost to the taxpayer of the government funding Bulb via a Special Administration Regime. Source: Ofgem, Statutory Consultation: Strengthening Financial Resilience, November 2022, p.22.

[59] Ofgem, Statutory Consultation: Strengthening Financial Resilience, November 2022, p.21.

[60] Ofgem, Statutory Consultation: Strengthening Financial Resilience, November 2022, p.21.

[61] Note: The traditional "Big Six" includes British Gas, EDF, E.ON, Npower, Scottish Power and SSE. Source: NERA analysis of Ofgem's Gas Supply Market Shares by Company: Domestic (GB), found at: https://www.ofgem.gov.uk/energy-data-and-research/data-portal/retail-market-indicators

generally also owned generation businesses, but with legal unbundling – one owner could own two separate businesses licensed to provide generation and retail supply services.

125. Alongside the vertical unbundling, the Big 6 licensees are subject to three conditions on the relationship between generation and retail supply interactions:[62]

A. **Condition 16 Segment reporting:** Publication of separate business accounts that distinguish the licensed business from any other business under the same financial accounts. Typically these are subject to regulatory accounting standards or guidelines, particularly with regards to the allocation of costs across businesses.

B. **Condition 17 on Non-Discrimination:** A requirement that the licensee does not sell or offer electricity to one purchaser at prices that are materially different to other comparable wholesale purchasers (after accounting for the other terms of the contract e.g., volumes, dates, interruptability etc.).

C. **Condition 17A on prohibition of cross-subsidies:** A requirement that the generation business shall not provide or receive any cross-subsidy from any other business of the licensee.

126. In 2008, Ofgem undertook an investigation into the functioning of wholesale and retail markets (the Energy Supply Probe), based on market power concerns. In the investigation, Ofgem stated its intention to facilitate entry to "*strengthen competitive pressure on the Big 6 suppliers*."[63]

127. In the years following the Energy Supply Probe, Ofgem's policies sought to facilitate entry, in part by reducing the costs associated with establishing and operating a retail business, such as introducing:[64]

A. <u>Retailer Exemptions</u>: Ofgem exempted small suppliers from government social and environmental obligations that would otherwise require them to recover additional costs from domestic customers through their energy bills.[65] For example, Ofgem exempted retailers with fewer than 250,000 domestic customers from the costs of the Energy Company Obligation (ECO), feed-in tariffs (the UK government's main financial incentive to encourage the uptake of small-scale renewable technology), and the Warm Home Discount.[66] These exemptions afforded small suppliers a cost advantage relative to the Big Six suppliers, that had to recover the costs of these initiatives through the energy bills charged to customers.[67] For example, the ECO exemption was estimated to be worth a cost saving of £36 to £60 per domestic customer per annum.[68]

B. <u>Mechanisms to promote wholesale market liquidity</u>: Ofgem introduced a "Secure and Promote" Licence Condition in 2014 to address concerns that poor wholesale market liquidity was acting as an entry barrier in both the generation and retail market.[69] As part of these conditions,

62 Electricity Generation Standard Licence Conditions

63 Ofgem, Energy Supply Probe – Initial Findings Report, October 2008, p.6.

64 Ofgem, Energy Supply Probe – Initial Findings Report, October 2008, p.6.

65 Competition and Markets Authority ("CMA"), Energy Market Investigation, June 2016, p.365.

66 Competition and Markets Authority ("CMA"), Energy Market Investigation, June 2016, p.366.

67 Competition and Markets Authority ("CMA"), Energy Market Investigation, June 2016, p.365.

68 CMA, Energy Market Investigation, June 2016, p.366.

69 Ofgem, WPML: decision letter, January 2014, p.1.

Ofgem introduced a market making obligation (MMO) which compelled the Big Six to post bid-offer spreads for baseload and peakload forward contracts.[70] Through the MMO, Ofgem aimed to provide regular opportunities to access forward products for smaller retailers, establish a reference of prices along the forward curve and to increase wholesale competition, to benefit the retail market and consumers.[71] Ofgem noted that the MMO would impose costs for the Big Six mandated to provide bid-offer spreads and provide accessible products for small suppliers.[72]

128. In 2018, the Government also mandated Ofgem to implement the Default Tariff Cap (DTC), for all domestic customers, which took effect from 1 January 2019.[73] The DTC, set now on a quarterly basis, limits the amount retailers can charge domestic customers for electricity and gas provision.[74] The DTC is set through a building blocks approach of the different components of a customer's bill (including network charges, wholesale energy costs, and balancing costs).

129. The largest cost component of the cap is the costs for retailers to purchase energy in the wholesale market for its customers. The cost of wholesale energy allowance is set based on the cost of forward products that deliver energy during the cap period (and in the 9 months following). They therefore reflect an assumed hedging profile of retailers, purchasing products up to 16.5 months ahead of delivery.[75]

7.2. The Number of Retailers Grew Sixfold Between 2010 and 2018 but has Been in Near-Constant Decline Since

130. As shown by Figure 7.1, the number of retailers in Great Britain increased sixfold from 12 in 2010 to a peak of 70 retailers in 2018, supported by Ofgem's regulations that lowered the cost for small retailers to enter and operate in the market. The entrant retailers also successfully captured market share from the Big Six retailers. For example, the market share for the traditional Big Six declined from 99 per cent to 76.5 per cent between 2010 and 2018, as new entrants grew their customer bases.

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[70] Ofgem, WPML: statutory consultation on the 'S&P' licence condition, November 2013, p.35.

[71] Ofgem, WPML: statutory consultation on the 'S&P' licence condition, November 2013, pp.18, 4.1.

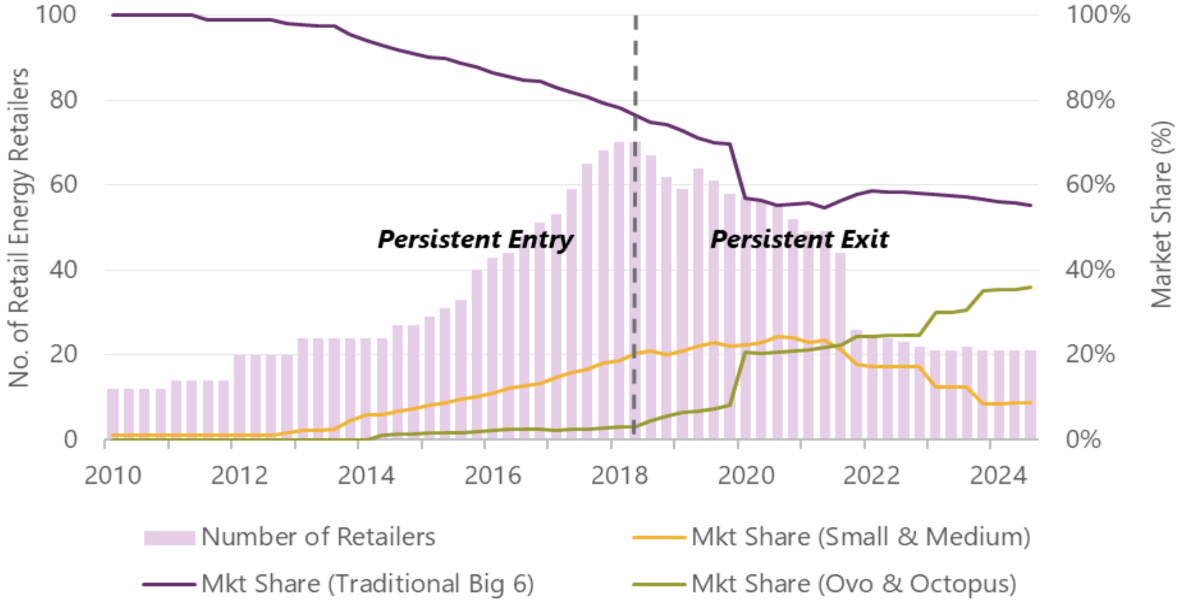
[72] Ofgem, WPML: statutory consultation on the "S&P" licence condition – Impact Assessment, November 2013.

[73] Ofgem, Default tariff cap – Overview document, November 2018.

[74] Ofgem, Default tariff cap – Overview document, November 2018, p.12.

[75] Ofgem sets the wholesale cost allowance in each cap period based on a prescribed "3-1.5-12" where (i) Ofgem averages the prices of specified baseload and peakload forward contracts over a 3-month observation period, (ii) the relevant forward contracts are those that will be delivered over the 12-months from the start of the cap period and (iii) Ofgem allows a 1.5-month window between the end of the observation period and the start of the cap period to enable retailers to communicate the update charges to consumers.

Figure 7.1: Retailer Numbers Peaked at 70 in 2018 But 65 Retailers Have Since Exited



Notes: Ofgem data for total retailers is recorded annually until June 2014. As such, the number of retailers in 2010-2013 is flat across each quarter within the year.
Source: NERA Analysis of Ofgem Retail Market Indicators, available at: https://www.ofgem.gov.uk/energy-data-and-research/data-portal/retail-market-indicators

131. However, 65 retailers have exited the market since 2018 and just 21 retailers currently operate, a 70 per cent reduction from the peak in 2018 (and only 9 more than the original number operating alongside the Big Six in 2010).[76] As shown by Figure 7.1, the decline in the number of retailers operating in the market is characterised by three phases since the peak in 2018:

A. A steady decline from 70 retailers in the first half of 2018 to 52 retailers by the end of 2020.

B. A sharp decline from 52 retailers at the end of 2020 to just 26 retailers by the end of 2021.

C. Since 2021, the number of retailers has not rebounded but has remained relatively stable at an average of 22 retailers between 2022 and 2024.

132. In Great Britain, the costs of a retailer failure are spread across all customers via an uplift to their bills under the Supplier of Last Resort (**SoLR**) process (or alternatively, through taxation if the government runs a retailer under the Special Administration Regime (**SAR**), a process used only for Bulb which failed with 1.5 million customers).[77,] Ofgem estimates the cost of the retailer failures in 2021 alone amounts to roughly £337 per domestic customer across both processes.[78]

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[76] NERA analysis of Ofgem Retail Market Indicators, available at https://www.ofgem.gov.uk/energy-data-and-research/data-portal/retail-market-indicators

[77] When a retailer goes out of business, Ofgem usually appoints a SoLR to take on the customers of the retailer. The SoLR can claim a Last Resort Supply Payment (LRSP) for costs incurred, recovered from all customers. See Ofgem (2016), Guidance on SoLR & energy supply company administration orders

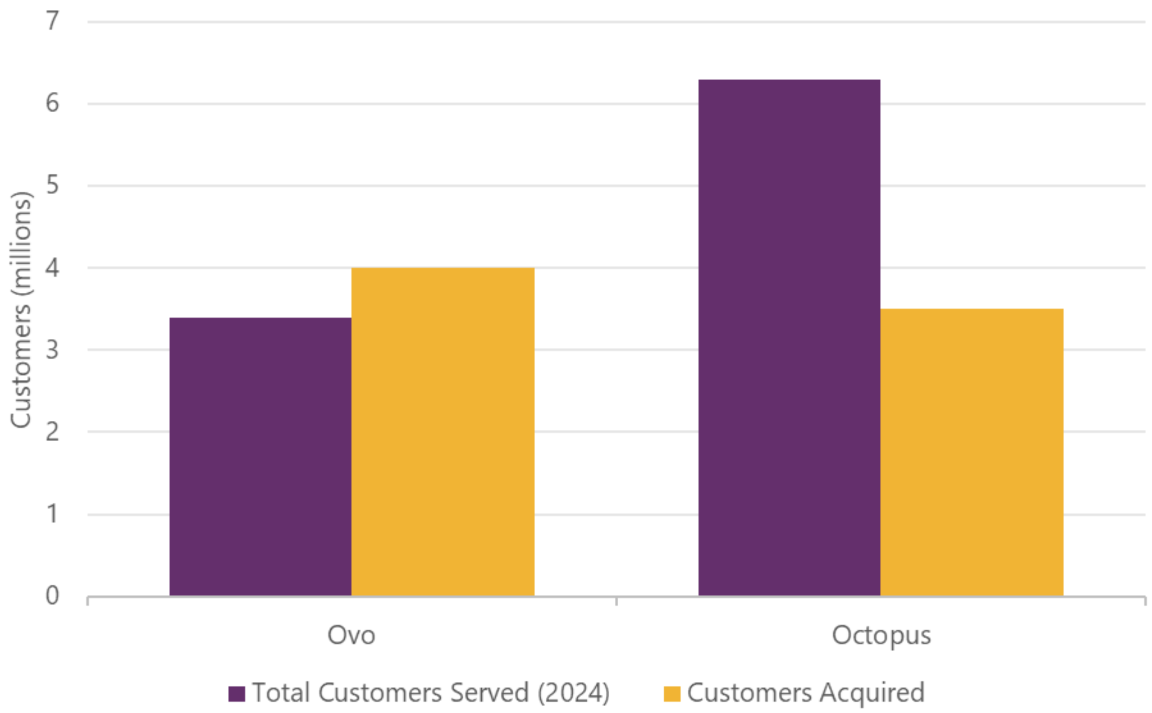
Source: National Audit Office, Investigation into Bulb Energy, March 2023, p.5.

[78] £337 per domestic customer is calculated as £9.1 billion divided by 26.98 million domestic customers as per Ofgem's estimate in the Ofgem energy consumer archetypes update 2024.

Source: Ofgem, Statutory Consultation: Strengthening Financial Resilience, November 2022, p.22.

133. Figure 7.1 also shows that a small number of new entrants have successfully grown their market share. Namely, Octopus and Ovo represent a combined 36 per cent of the market in 2024. However, as indicated by Figure 7.2, an important part of Octopus and Ovo's growth has been fuelled by acquisitions of existing suppliers. For example, Ovo acquired a Big Six retail business (SSE) in 2020, which increased Ovo's customer base by 3.5 million and market share by roughly 12 percentage points.[79] Indeed the figure below shows that Ovo has acquired more customers than it currently serves, as Ovo's market share has declined persistently since acquiring SSE. Similarly, Figure 7.2 shows that Octopus has acquired a combined 3.5 million customers, including roughly 2.8 million from Bulb and Shell Energy Retail alone, which represents over half of the 6.3 million customers that it currently serves.[80,81]

Figure 7.2**: Octopus and Ovo's Growth Has Been Fuelled by Acquisitions of Existing Suppliers**



Note: Customer numbers as of 2024 estimated by multiplying Ovo and Octopus' market share by the total number of domestic customers reported by Ofgem (26.98 million).
Source: NERA Analysis of Ofgem Retail Market Indicators, available at: https://www.ofgem.gov.uk/energy-data-and-research/data-portal/retail-market-indicators

79 OVO Energy (Website), Ovo Energy to acquire SSE Energy Services in a landmark transaction. Available at: https://company.ovo.com/ovo-energy-to-acquire-sse-energy-services-in-a-landmark-transaction/

80 Octopus Energy (Website), Group results for FY24. Available at: https://octopus.energy/press/octopus-energy-group-results-for-fy24-delivered-07-profit-margin-tripled-non-uk-customer-base-and-increased-net-assets-to-17bn/

81 National Audit Office, Investigation into Bulb Energy, March 2023, p.5.

7.3. Some Retailers' Adoption of Short-Term Hedging Strategies was a Key Contributor to the Failures in 2021

134. Following the exit of 29 retailers in 2021, Ofgem conducted a review of its historical policy of promoting growth in retail competition.[82] While Ofgem apportioned some blame to the volatility in the wholesale gas and electricity markets, it also accepted that its regulatory environment contributed to the extent of the failures and the costs imposed on customers. It states:[83]

> *"**The focus on expanding competition and promoting choice, while benefitting consumers through lower prices, ultimately led to low financial barriers to entry and light regulation of financial risks.** The energy crisis exposed problems with this retail market model, leading to a large number of supplier failures towards the end of last year, ultimately costing all consumers through higher bills".*

135. There are two main ways that entrant retailers can sustainably compete in the market:

A. Providing Better Products (i.e., Innovating): New entrants can compete on product offering by innovating to provide better products than incumbent retailers, e.g., offering spot-price based tariffs, technology offerings.

B. Lower Prices: Alternatively, new entrants can aim to compete on price for the same services offered by incumbent retailers, for instance, by realising efficiency gains.

136. There is little evidence to suggest that the entrant retailers successfully competed on quality with the Big Six retailers. For instance, the UK Government found that innovation was limited and that customers had a "very limited set of choices" in the retail market.[84] Citizens Advice also determined that the retailers that failed in 2021 scored poorly for customer service.[85]

137. Rather than competing on quality, the UK Government found that most offers only differed by price.[86] However, Ofgem identified that many new entrants competed on price and grew by engaging in a risky strategy that relied on undercutting the prices offered by a long-term hedging strategy incentivised by the DTC.[87]

7.3.1. New entrant retailers took risk and adopted short term hedging strategies designed to undercut longer-term strategies of established businesses

138. Some new entrants pursued business models that attracted customers not through service offerings or sustainable efficiency gains over incumbent retailers but by taking on risk to undercut

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82 Ofgem, Statutory Consultation: Strengthening Financial Resilience, November 2022.

83 Source: Ofgem, Statutory Consultation: Strengthening Financial Resilience, November 2022, p.5. (Emphasis added)

84 Department for Energy Security and Net Zero, Policy Paper – Delivering a better energy retail market: a vision for the future and package of targeted reforms, July 2023.

85 Citizens Advice, Written Evidence to the BEIS Select Committee from Citizens Advice, p.6

86 Department for Energy Security and Net Zero, Policy Paper – Delivering a better energy retail market: a vision for the future and package of targeted reforms, July 2023.

87 Department for Business, Energy and Industrial Strategy Committee, Energy Pricing and the Future of the Energy Market, July 2022, p.13.

the price offered by incumbent suppliers pursuing long-term hedging strategies.[88] This is indicated in Figure 7.3, which shows that new entrants systematically offered fixed-price tariffs that undercut the fixed-price tariffs of the Big Six retailers.

139. A portion of the tariff differential between the Big Six retailers and new entrants may be explained by Ofgem's exemptions that reduced small retailers' operating costs, as Section 7.1 explains. However, Ofgem also found that some new entrants offered unsustainably low (fixed price) tariffs based on a short-term hedging strategy that aimed to undercut the prices that providers employing long-term hedging strategies could charge.[89]

140. A supplier that pursues a long-term hedging strategy, such as the hedging strategy prescribed by the DTC, sets stable prices that lags (and smooths) changes in wholesale prices. This is because the supplier sets prices with reference to historical (long-term) hedging contracts that a supplier has already bought to serve its customer base under a long-term hedging strategy.

141. For instance, Figure 7.4 shows that changes in the level of the DTC (set under a prescribed, long-term hedging strategy) lag changes in the wholesale price. For example, wholesale prices increased almost continuously from May 2020 onwards, yet the DTC *decreased* until April 2021, as the DTC was still capturing the decline in wholesale prices across 2019 and the first half of 2020.

142. In contrast, a supplier that uses a short-term hedging strategy purchases power at the wholesale price close to delivery. Thus, by taking risk that actual wholesale costs at the time of delivery were below the allowance in the DTC and the fixed-price tariffs set by the Big Six retailers backed by long-term hedges, small retailers could offer attractive low tariffs to gain market share by buying power closer to delivery.[90]

143. However, this is not a sustainable form of competitive advantage since a supplier using a short-term hedging approach is more exposed to the volatility in the wholesale market. Indeed, when wholesale prices rose in 2021, retailers that employed short-term hedging strategies could not recover the higher wholesale costs relative to their fixed price tariffs and ultimately became insolvent. This led to over 29 retailers exiting the market at an estimated cost of £337 per domestic customer.[91]

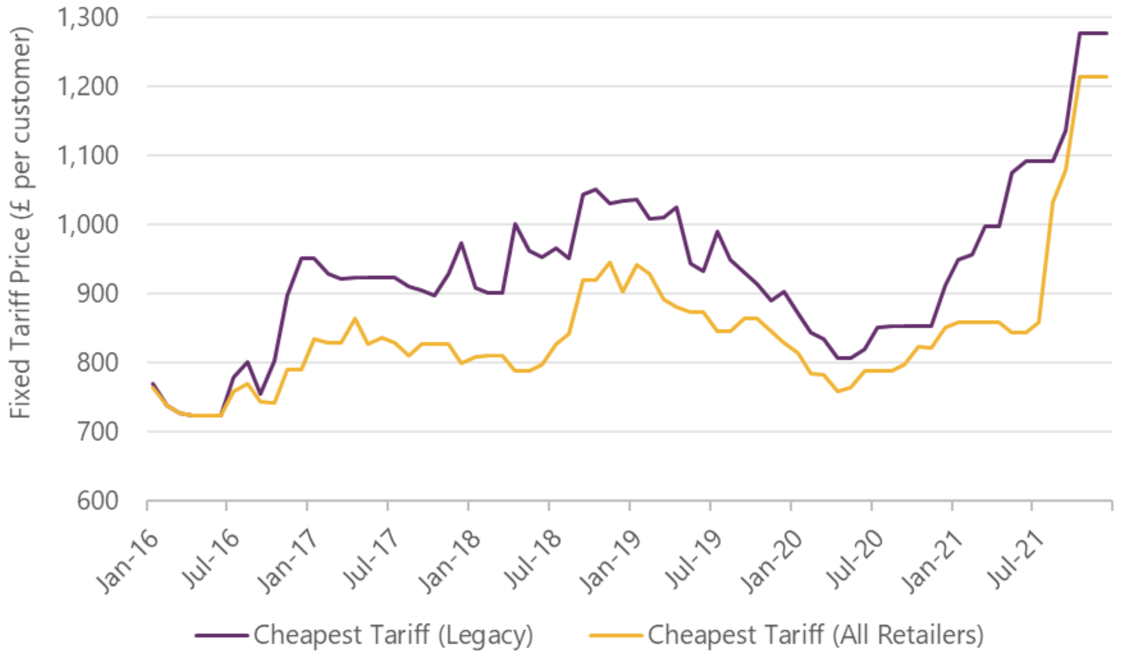
88 Ofgem, Statutory Consultation: Strengthening Financial Resilience, November 2022, p.9

89 Ofgem, Statutory Consultation: Strengthening Financial Resilience, November 2022, p.24

90 Department for Business, Energy and Industrial Strategy Committee (July 2022), Energy Pricing and the Future of the Energy Market, p.12.

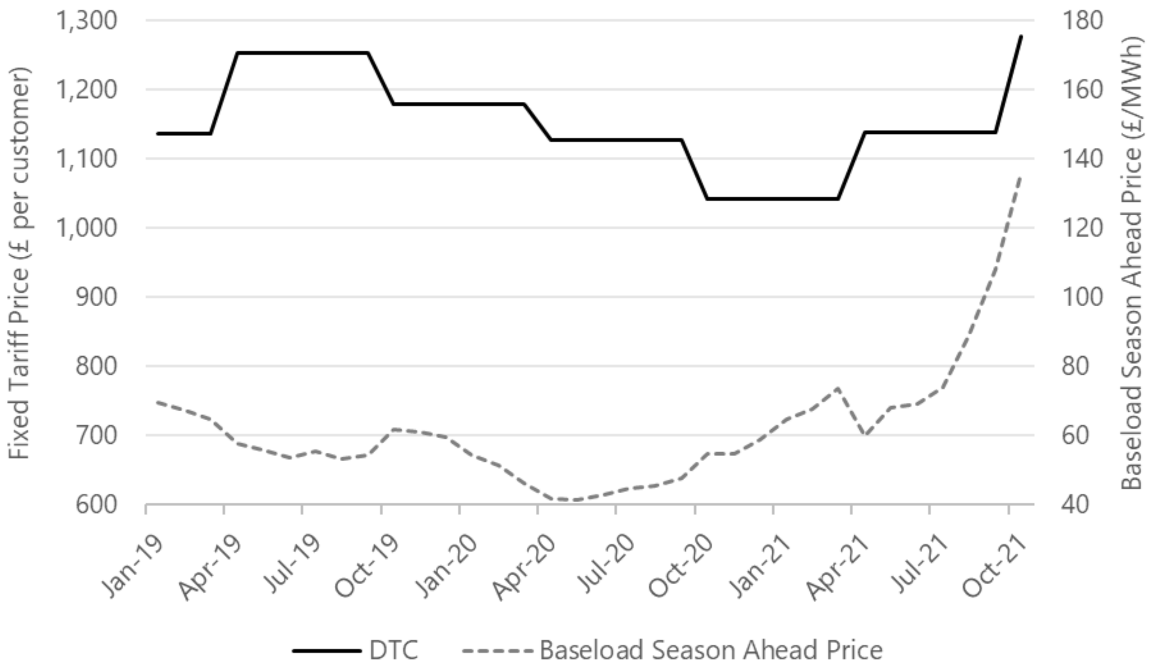
91 Ofgem, Statutory Consultation: Strengthening Financial Resilience, November 2022, p.22.
Note: £9.1 billion includes (i) £2.6 billion of SoLR costs for supplier failures paid for by consumers on their bills and (ii) £6.5 billion for the cost to the taxpayer of the government funding Bulb through a Special Administration Regime. The value of £325 per domestic customer is calculated as £9.1 billion divided by 27 million domestic customers as per Ofgem's estimate in the Ofgem energy consumer archetypes update 2024, available at: https://www.ofgem.gov.uk/sites/default/files/2024-02/Ofgem_archetypes_update_2024_FinalReport_v4.1.3.pdf

Figure 7.3: Some Retailers Offered Fixed Price Tariffs Well Below the Tariffs Offered by the Big Six Retailers



Source: NERA Analysis of Ofgem Data (Retail Market Indicators, available at: https://www.ofgem.gov.uk/energy-data-and-research/data-portal/retail-market-indicators)

Figure 7.4: Changes in the DTC Lags Changes in Wholesale Prices Given its Prescribed (Backward-Looking) Hedging Strategy



Source: NERA Analysis of Ofgem Data (Retail Market Indicators, available at: https://www.ofgem.gov.uk/energy-data-and-research/data-portal/retail-market-indicators)

7.3.2. Retailers operated with limited regulatory oversight which led to a moral hazard problem and the ability to operate risky business models

144. Ofgem recognises that small retailers could afford to take such strategies as set out in Section 7.3.1 given insufficient regulatory oversight of the business models and operating practices of new entrants.[92] Specifically, new entrants benefited from:

A. Reliance on Customer-Funded Working Capital: Ofgem determined that retailers could enter the industry with minimal levels of their own capital and did not typically need to raise external finance from debt or equity providers.[93] Rather, retailers relied on "free" sources of finance in the form of customer credit balances (i.e., customers paying for energy ahead of its use through direct debit) and renewable obligation receipts to fund operations.[94, 95] This meant that retailers faced an asymmetric distribution of risk (owners faced limited downside risk from insolvency having contributed little of their own capital, but retained profits from upside scenarios) which incentivises excessive risk-taking (i.e., moral hazard).

B. Minimal Due Diligence of the Business Models of New Entrants: That retailers contributed minimal levels of their own capital meant that retailers faced low downside risk in the event of failure. As such, owners' risk appetites were skewed towards pursuing excessively risky strategies that systematically under-hedged the energy requirements of its customer base.[96] Ofgem acknowledged that it operated a 'low bar' approach to licensing energy suppliers, which included insufficient due diligence of new entrants' business models.[97] Moreover, given that retailers did not require external finance, outside investors could not play a role in moderating the entry of businesses with excessively risky business models.[98]

C. Lack of Minimum Financial Resilience Standards: Retailers could operate with low levels of capital, leaving retailers susceptible to market shocks (compounded by the fact that the DTC limited the ability to pass through costs to customers).[99]

145. Ofgem has since pursued policies that have toughened scrutiny on new entrant suppliers and their financial resilience, including limiting their ability to use customer money as working capital.[100]

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92 Ofgem, Statutory Consultation: Strengthening Financial Resilience, November 2022, pp.5 & 21

93 Ofgem, Statutory Consultation: Strengthening Financial Resilience, November 2022, p.21

94 Ofgem, Statutory Consultation: Strengthening Financial Resilience, November 2022, p.21.

95 Customers typically pay a fixed amount for energy in each month, rather than paying more in Winter and less in Summer. A customer credit balance means that a customer has overpaid relative to its energy consumption over a period and is owed money by the retailer. Renewable Obligation receipts are money collected by retailers on behalf of the Government, used to fund a government renewables scheme. Under previous regulations, retailers could use both customer credit balances and RO receipts as free sources of working capital.

96 Ofgem, Statutory Consultation: Strengthening Financial Resilience, November 2022, pp.9&21

97 National Audit Office (June 2022), The Energy Supplier Market, p.38.

98 Ofgem, Statutory Consultation: Strengthening Financial Resilience, November 2022, p.21

99 Ofgem, Statutory Consultation: Strengthening Financial Resilience, November 2022, p.9

100 Ofgem, Strengthening Financial Resilience – Minimum Capital Requirement and Ringfencing CCBs by Direction, 2023.

7.4. The GB Case Study Demonstrates that Retailers Adopting Short-Term Hedging Strategies May Not be Conducive to Sustainable Competition in the Sector

146. The recent retail history in Great Britain provides several lessons for the Electricity Authority and its proposals in New Zealand.

147. **Key Lesson 1: Availability of hedging products correlated to higher retailer entry at a cost to parties mandated to make products available.** Ofgem determined that the MMO it introduced in 2014 did help to support liquidity in the market.[101] Moreover, Ofgem argued the MMO had a positive effect in reducing bid-offer spreads and in increasing traded volumes, albeit that the larger volumes may be due to market volatility.[102] While Ofgem does state that this is not entirely attributable to the policy, it is also notable that the number of retailers increased two to three-fold during the period the MMO was in place, from 24 at the start of 2014 to 58 retailers at the end of 2019.[103] However, provision of these products is not without cost which in the case of GB was borne by the incumbent gentailers.

148. **Key Lesson 2: Without regulatory oversight, new entrant retailers have incentives to adopt risky strategies to compete on price with incumbents following long-term hedging strategies.** As Section 7.3.1 discusses, the evidence in Great Britain suggests that the pressure to grow a retail business by competing on price may create perverse incentives for retailers. For example, Ofgem found that small suppliers pursued short-term hedging strategies, despite having access to hedging products.[104] As Section 7.3 explains, suppliers that pursue short-term hedging strategies gamble that wholesale prices fall to outcompete suppliers that pursue long-term hedging strategies (e.g., the strategy embedded in the DTC).

149. Independent retailers in New Zealand may face this perverse incentive since gentailers offer stable retail prices that lag changes in wholesale costs. Therefore, independent retailers could have an incentive to adopt strategies that undercut gentailers' tariffs by purchasing power closer to delivery. However, this is not a sustainable form of competitive advantage. Rather, when wholesale prices spike, independent retailers would either (i) appear uncompetitive versus the stable tariffs the gentailers can offer or (ii) become insolvent if they have agreed fixed-price tariffs and do not hold sufficient risk capital to remain solvent in the face of losses.

150. The evidence that small suppliers pursue short-term hedging strategies is not specific to Great Britain but is similarly supported by the European Commission (**EC**). For instance, the EC identified that retailers' systematic lack of hedging led to heightened retailer failure during the energy crisis in 2021.[105] Whilst the EC reported that small retailers in Europe face difficulties accessing hedging products, it is unclear whether small retailers would purchase hedging contracts even if available given that:

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101 Ofgem, Secure and Promote review: Consultation on changes to the special licence condition, December 2017, p.5.

102 Ofgem, Power Market Liquidity, December 2023, p.7.

103 NERA analysis of Ofgem Data (Retail Market Indicators, available at: https://www.ofgem.gov.uk/energy-data-and-research/data-portal/retail-market-indicators)

104 Ofgem, Statutory Consultation: Strengthening Financial Resilience, November 2022, p.21.

105 European Commission, Electricity Market Design Consultation Document, p.23.

A. As found in Great Britain, the primary form of competition between incumbent utilities and new entrants is price.

B. Following similar long-term hedging strategies will allow for little differentiation in the largest cost component of retail tariffs i.e., the cost of purchasing wholesale energy.

C. New entrants are therefore likely to undertake different hedging strategies, some of which may involve heightened risk, in order to gain market share from incumbent utilities.

D. Small retailers may have greater uncertainty about the level of future demand they must hedge for given that they may have less certainty over their future number of customers (given their pursuit of a growth strategy in the market).

E. Purchasing hedging contracts is costly and ties up retailers' working capital.[106]

151. However, to ensure that suppliers (and in turn customers) are less exposed to price volatility from the wholesale markets, the EC implemented a reform that grants national regulatory bodies the power to ensure electricity retailers implement effective hedging strategies.[107]

152. **Key Lesson 3: Fixating on retailer entry without ensuring sustainability in new entrant business models may end up creating more costs for customers than the benefits of competition and innovation that new entrants may drive**. A policy environment that promotes retail entry without ensuring there are adequate standards and controls for vetting and monitoring new entrants may ultimately create more costs for consumers than the benefits that competition can drive. Whilst Ofgem noted that customer bills were lower in the short-term, it acknowledged that the entry of inefficiently risky retailers added costs to consumers in the long run.[108] The estimated cost of £9.1 billion associated with the 29 retailers that exited the market in 2021 were ultimately picked up by domestic customers and the government.[109]

153. To encourage sustainable competition, regulatory authorities need to ensure adequate regulatory scrutiny of new entrant suppliers. Ofgem has since moved to strengthen its standards and controls over retailers following the failures in 2021. For example, in 2023, Ofgem mandated suppliers to ringfence 100 per cent of RO receipts and 20 per cent of gross credit balances to reduce access to free sources of working capital that skewed retailers' incentives towards using excessively risk business models.[110,111] As evidenced in Section 7.2, since these new strengthened standards and controls have come into effect, the number of new entrants has not increased.

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106 Centre for European Reform, Will the EU's Reform of Retail Electricity Markets Help Consumers, April 2023, p.2.

107 European Commission, amending Directive EU (2024/1711), article 18, June 2024.

108 Ofgem, Statutory Consultation: Strengthening Financial Resilience, November 2022, p.9.

109 Ofgem, Statutory Consultation: Strengthening Financial Resilience, November 2022, p.22.
Note: This includes the cost to the taxpayer of the government funding Bulb through a Special Administration Regime. The value of £325 per domestic customer is calculated as £9.1 billion divided by 26.98 million domestic customers as per Ofgem's estimate in the Ofgem energy consumer archetypes update 2024, available at: https://www.ofgem.gov.uk/sites/default/files/2024-02/Ofgem_archetypes_update_2024_FinalReport_v4.1.3.pdf

110 Ofgem, Strengthening Financial Resilience, 2023.

111 Ofgem, Strengthening Financial Resilience – Minimum Capital Requirement and Ringfencing CCBs by Direction, 2023.

8. Recommendations

154. As we have described in Chapters 6 and 7, and shown through real-world British experience in Chapter 8, the types of interventions that the EA proposes carry significant risks in terms retail price volatility and dampened investment incentives, both of which would be borne by consumers through higher and more volatile energy bills.

155. Nonetheless, if the EA does decide to pursue these reforms, we provide a number of recommendations for how to amend or further clarify its proposals on level playing fields, such that they provide genuine opportunities for retail entry while limiting the risk that they unfairly hindering gentailers' ability to operate their businesses, and without creating a world of volatile retail prices.

8.1. Clarifications to Non-Discrimination Obligation

156. Most importantly, the non-discrimination obligation, especially insofar as they relate to the cross-subsidy requirement, must be clarified to ensure that customers do not lose the value of vertical integration and the long-term price stability that can come from it.

157. The EA should explicitly recognise the temporal principle of risk management, i.e. that a longer-term hedging strategy produces more stable retail prices than a shorter-term strategy. Retailers adopting a "just in time" strategy may sometimes be able to deliver power for a lower cost (i.e. when wholesale prices are falling), but not when prices are increasing. The long-term price stability is itself valuable to customers, for whom electricity is a significant cost item that may need to be budgeted around.

158. The cross-subsidy and the non-discrimination obligations should be considered on different horizons.

159. The cross-subsidy requirement should be a backward-looking measure, reflecting the cost of products implicitly procured internally over the past years leading up to the delivery period. Furthermore, gentailers should have flexibility in defining and demonstrating that backward-looking profile, which could implicitly change as the gentailer's capacity mix and customer profile changes.

160. The non-discrimination requirement should be forward-looking and represent the types of internal hedges that a gentailer would procure for delivery in future years. This would ensure an independent retailer would have the opportunity to approximate the strategy of the gentailer, by the time of the future delivery period.

161. If this approach is not taken, and compliance with the cross-subsidy requirement involves demonstrating that the retail business is profitable at *current* forward looking wholesale prices, then this will require gentailers who smooth retail prices over the long run to sell hedges to independent retailers at below market rates.

162. It may be possible to limit some of the harms (in terms of retail pricing and investment incentives) that would result from this, if constraints are placed on the purchases of independent retailers:

A. Independent retailers should have a commitment to purchase from the gentailer through periods of rising and falling prices, rather than cherry pick and buy from gentailers when prices are rising and purchase shorter-term hedges and spot electricity when prices are falling. This symmetrical strategy would replicate the terms of the implicit trade within a gentailer.

B. Independent retailers should not be allowed to purchase more than the demand of their retail book, as doing so would allow them to take advantage of artificial arbitrage opportunities.

8.2. Alternative solution: Market making of Peak and Super-Peak Contracts

163. Much of the analysis that the EA presents to justify its intervention relates to the availability and pricing of super peak contracts. However, as we describe in Section 2.1, the evidence that super peak contracts are only being made available on discriminatory terms is limited, and includes recognised but not quantified biases.

164. In order to ensure all parties have access to contracts, without unduly limiting the ability of gentailers to operate efficiently as well-hedged retailers, the EA could consider introducing a market-making obligation on super peak (and possibly peak) contracts.

165. In practice, this would involve requiring gentailers to make a certain volume of contracts available each day, and with a maximum bid-ask spread. If the gentailer offered contracts at an artificially high price, then the limit on the bid-ask spread would create an opportunity for another party to arbitrage, by *selling* contracts to the gentailer at an artificially high price.

166. Such a direct intervention would be a more targeted approach appropriate to the problem of limited access to and high pricing of super peak contracts, without creating so many additional complications or unintended consequences that a functional unbundling would.

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