Level playing field measures

Consultation paper

14 October 2025

ELECTRICITY AUTHORITY
TE MANA HIKO

Executive summary

The Electricity Authority Te Mana Hiko (the Authority) is consulting on proposed amendments to the Electricity Industry Participation Code 2010 (the Code) to impose principles-based Non-Discrimination Obligations (NDOs) on the four large generator-retailers – Contact Energy Ltd, Genesis Energy Ltd, Meridian Energy Ltd and Mercury NZ Ltd (together, the gentailers).

The NDOs form part of a package of pro-competition interventions designed to build confidence in the wholesale electricity market, and support competition and investment that will, over time, give New Zealanders better access to affordable electricity.

The Authority published an options paper on Level Playing Field measures (LPF Options paper) on 27 February 2025. The paper proposed introducing mandatory NDOs to address competition concerns in hedge markets,[1] arising from gentailer vertical integration and control of the flexible generation base. Our focus was on improving hedge contract liquidity, price, and even-handedness to support competition in retail markets.

The Authority received over 40 submissions on the LPF Options paper in May 2025 and had more than 20 direct engagement sessions with stakeholders between 23 and 25 June 2025.

After considering these submissions and carrying out further analysis, the Authority now proposes to implement amended principles-based NDOs that support targeted and timely implementation.

Summary of the proposed NDOs

The Authority is proposing a Code amendment to introduce six non-discrimination principles, supported by record-keeping and disclosure obligations. The proposed non-discrimination principles are listed in the table below. The intent of these proposals is to ensure that the gentailers cannot favour their own retail arms over other retailers in the availability or pricing of risk management contracts.

Non-discrimination principles

Principle	Proposed non-discrimination obligations
Principle 1: Non-discriminatory supply	(1) A gentailer must not discriminate between buyers for the supply of risk management contracts without an objectively justifiable reason. (2) A gentailer must not discriminate against buyers in favour of its own internal business units for the supply of uncommitted capacity without an objectively justifiable reason. (3) A gentailer must not discriminate against buyers in favour of its own internal business units when pricing risk management contracts without an objectively justifiable reason. (4) For the avoidance of doubt, subclause (3) requires pricing of risk management contracts in such a way as to ensure that any buyer that

[1] This paper uses the term “hedge” and “hedge market” to refer to risk management contracts, and their market(s). This is for stylistic reasons. The definitions of these terms can be found in the glossary.

	supplies electricity to end users at retail, that is as efficient with regard to operating costs as the gentailer's own retail internal business unit, and adopts a reasonable risk management approach, is not prevented from operating profitably.
Principle 2: Obligation to trade in good faith	A gentailer must engage with buyers in good faith and in a timely and constructive manner in relation to the supply of risk management contracts.
Principle 3: Objective credit assessments	A gentailer's credit terms and collateral arrangements relating to the supply of risk management contracts to buyers must reflect a reasonable, consistent and transparent assessment of the risk of trading with a buyer.
Principle 4: Equal access to commercial information	A gentailer must ensure that any commercial information relating to risk management contracts made available to its internal business units that compete with buyers is also made available to buyers at the same time.
Principle 5: Protection of confidential information	A gentailer must protect buyer confidential information and establish robust processes to prevent disclosure of buyer confidential information to, and use of buyer confidential information by, any of the gentailer's internal business units that may compete with the buyer.
Principle 6: Record-keeping	A gentailer must establish, maintain and keep records that demonstrate its compliance with these non-discrimination principles.

Details of the draft Code amendment are included in Appendix A.

The Authority has also prepared draft guidance on how it would expect gentailers to comply with the non-discrimination principles (see Appendix B). The Authority intends to finalise this guidance, following consultation with stakeholders, before any Code change takes effect. The guidance is intended to exist as a separate document that could be incorporated into the Code at a later point if necessary.

Key changes from the non-discrimination principles proposed in the LPF Options paper are set out further below.

Rationale for imposing NDOs: Risks to competition and confidence in the market

Hedge contracts allow new and independent retailers and generators to better manage their price risks. Hedges are therefore critical to enabling competition, which can encourage more generation investment, provide more choice to consumers, and put downward pressure on electricity prices. The gentailers control the flexible generation that backs these hedges.

In the LPF Options paper, the Authority expressed concern about the "risk that the combination of gentailer vertical integration and their control of flexible generation is hindering competition in generation and retail, and investment in new electricity generation". Independent retailers have complained about gentailers refusing to supply shaped peak and super-peak products, and that they faced margin squeezes.

The price and availability of certain types of hedges are affected by several factors including increased demand for risk management, relatively fewer flexible resources to back hedge contracts, and constrained ability to expand flexible resources in the short and medium term. But there are credible concerns that gentailers have the ability and incentive to individually influence the price or supply of hedge contracts and may be doing so in a manner that has competition implications.

Submissions helped us refine our understanding of the problem and prompted us to undertake further analysis. Our view now is that:

- It is less likely that the prices for super-peak hedges reflect a premium above competitive pricing levels than initially indicated in the paper *Reviewing risk management options for electricity retailer – issues paper* (RMR).
- Access to shaped hedges remains a concern.
- There are substitutes for super-peak hedges, but it will be several years before they are available in the quantities needed to provide competitive discipline.
- There is no definitive evidence of a margin squeeze, though some retail price offers were below wholesale contract prices in 2023.

High prices and limited access to shaped hedges may reflect scarcity but the Authority still cannot rule out super-peak hedge prices being non-competitive, reflecting the exercise of market power in conditions of scarcity.

The Authority sees an ongoing risk that gentailers have opportunities to use market power in a manner that would harm competition. While it might be less than first indicated in the RMR, the risk remains because independent retailers, in particular, largely depend on the gentailers for the risk management products they need to compete with those same gentailers in the retail market. Independent generators also depend on the availability of risk management products to sign the Power Purchase Agreements (PPAs) that underwrite their financing.

The scarcity and concentrated ownership of flexible generation means the risk to competition may increase over time as the scale of intermittent generation grows, reducing flexible generation as a proportion of the overall mix and increasing the relative market power of the parties controlling that flexible generation.

In part due to this ongoing risk, independent retailers lack confidence in the effective operation of hedge markets. Unless addressed, eroded confidence of market participants risks chilling competition in retail markets.

The proposed NDOs address this risk in a proportionate manner by requiring gentailers to implement systems and processes to demonstrate that they do not discriminate between other market participants and themselves when supplying risk management contracts. Alongside these obligations, the Authority is proposing additional interventions to improve the operation of the hedge market and help address concerns identified in submissions. In particular:

- strengthening trading of the super-peak standardised flexibility product, alongside the development of other hedge products as the market evolves

- an upcoming review of market making.[2]

Key modifications to the proposed regulatory response

Based on feedback on the LPF Options paper, the Authority is now proposing a more pragmatic approach to NDOs that would be faster to implement and easier to enforce. These changes simplify the proposed NDOs, removing an area of contention and potential ambiguity (internal hedge portfolios), without compromising on the core goal – addressing the risk to competition from access or price discrimination.

The Authority is proposing to more directly test for gentailer discrimination in the pricing of risk management products in favour of their own retail business, or anticompetitive suppression of their retail prices, by requiring gentailers to regularly perform a Retail Price Consistency Assessment (RPCA). RPCAs are to be undertaken to satisfy subclause (3) of Principle 1.

This assessment will involve gentailers providing transparency on the link between their retail prices and the expected cost of supply. This will give other retailers confidence to compete through assurance that a gentailer has not assumed an unjustifiably low cost of supply when setting its own prices compared to expected market prices, or otherwise inappropriately suppressed its retail margins to the detriment of downstream competitors.

The Authority will develop guidance on the details and key parameters for the RPCAs and the design process will involve seeking input from participants. RPCA guidance on methodology and key inputs will promote comparability and confidence in the measures.

This approach replaces the previously proposed construction of an “economically meaningful internal hedge portfolio”. After reviewing submissions, the Authority believes that an internal hedge portfolio requirement would be impractical and time consuming.

The proposed NDOs would require that a gentailer allocate its uncommitted capacity on a non-discriminatory basis. Regular disclosure of uncommitted capacity would provide greater transparency on the extent to which constrained access to hedges reflects scarcity or withholding. This approach is complemented by our intention, subject to consultation, to rely more heavily on market making to improve liquidity for key wholesale inputs. Due to the complexity involved, the Authority is proposing to provide gentailers the flexibility to apply their own methodologies for quantifying and allocating uncommitted capacity. The Authority may choose to refine or standardise this methodology during the initial phases of implementation, subject to consultation.

The Authority now also proposes a new principle requiring gentailers to trade in good faith, including by engaging with buyers in a timely and constructive manner.

A core part of the proposed design of the principles-based regime is to require gentailers to put robust processes in place to demonstrate their compliance. This includes:

- director certification that the gentailer has complied with the non-discrimination principles
- requirements to self-report any breaches of the principles

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2 Electricity Authority, “Electricity Authority moves to level the power playing field”, 19 August 2025 https://www.ea.govt.nz/news/press-release/electricity-authority-moves-to-level-the-power-playing-field/

- regular reporting to the Authority and the public – including an interim report six months after the NDOs come into force, ongoing annual reporting demonstrating compliance with the principles, and six-monthly RPCAs.

The principles would also apply to the negotiation of power purchase agreements (PPAs). The Authority also intends further work to develop new standardised firming products through a co-design process to facilitate the firming of PPAs.

The Authority is proposing a different implementation and escalation pathway to that outlined in the LPF Options paper. The Authority will develop guidance on the application of the principles and the RPCAs. Over time, more prescription may be needed as we gather more information and develop insights into the implementation of the NDOs. The Authority had previously proposed an escalation where all hedges would have to be traded through a regulated market, known as Step 3. The Authority is no longer proposing this.

The Authority also intends to undertake an effectiveness review in which we consider the impact of our broader package of pro-competition reforms, including the new standardised super-peak hedge product, and our review of market making. The Authority proposes that this commence in 2027 following receipt of the first tranche of gentailers' annual reports.

Other matters relevant to our proposals

There was extensive discussion in submissions about the costs and benefits of vertical integration. In the Authority's view, risks to competition arise when vertical integration is combined with market power. Vertical integration can also somewhat mitigate wholesale market power in electricity markets. Addressing vertical integration in itself at this time is not a solution to the underlying market power issues and we are not proposing any interventions to unbundle or undo vertical integration.

Some submitters argued that NDOs would raise retail prices because gentailers would not be able to manage wholesale price volatility for the benefit of their customers. The Authority acknowledges that there may be good reasons for a retailer to look through periods with slim margins in the near-term. In developing guidance on the RPCAs, the Authority will seek to balance the ability for gentailers to manage through short-term volatility with any signs of persistently low margins that would foreclose competition in retail markets.

A number of submitters raised issues with both rising fuel prices and a scarcity of flexible generation as factors driving the shortage of shaped hedge products. These issues were part of the Government's review of electricity market performance, and proposed measures in response, released on 1 October 2025. The Authority does not intend to undertake further work on virtual disaggregation at this time.

The Authority is proposing to repeal the requirements for reporting of Internal Transfer Prices (ITP) because the Post Implementation Review did not find this information useful in its current form.[3] The proposed RPCA requirements, if implemented, would better address the issues that the ITP requirements aimed to address. Retention of the ITP regime could also cause confusion.

3 Electricity Authority, Internal Transfer Price and Retail Gross Margin post implementation review, 7 November 2024, https://www.ea.govt.nz/documents/5981/RGM_and_ITP_post_implementation_review.pdf.

A regulatory statement has been prepared for consultation. The proposal has been assessed against alternative approaches to achieve the Authority's objectives, and the Authority currently considers that the proposal's expected benefits are likely to exceed the costs and that it is likely superior to the alternative options.

Proposed implementation steps

The Authority is proposing a number of steps to give confidence to market participants and other stakeholders that NDOs will be implemented quickly and effectively (subject to the outcome of this consultation).

These steps will afford the Authority, gentailers and other stakeholders, where relevant, time to work together to implement and refine the NDOs, the RPCAs and guidance as matters of priority. These are outlined in the table below.

Proposed implementation timeline

Proposed Dates	Implementation Steps
November 2025	Industry engagement on RPCA guidance commences
February/March 2026	Code change published
April 2026	RPCA guidance published
1 July 2026	Commencement date First RPCA provided to the Authority, six monthly thereafter Gentailer NDO implementation plans to be published
February 2027	Interim reports provided to the Authority (and published within five working days) Second RPCA provided to the Authority, as part of Interim Reports Authority to subsequently consider whether to make RPCA guidance mandatory
April 2027	Electricity Authority feedback on interim reports[4]
September 2027	Annual reports provided to the Authority (and published within five working days) Third RPCA provided to the Authority, as part of annual reports
February 2028	Fourth RPCA provided to the Authority, as part of ongoing requirement for half-year RPCA reporting

[4] Our preference is to be transparent about this feedback, at least in terms of the issues raised. We will assess how best to communicate our views to all stakeholders at the time, acknowledging that some feedback may be best provided confidentially to the relevant gentailer only.

Contents

1. What you need to know to make a submission

What this consultation is about

1.1. This paper builds on the policy proposal set out in the options paper published by the Electricity Authority Te Mana Hiko (the Authority) in February 2025 (the LPF Options Paper).

1.2. The purpose of this paper is to consult with interested parties on two related Code amendment proposals by the Authority to:

(a) place non-discrimination obligations on the four large gentailers in relation to the supply of risk management contracts; and

(b) repeal the Code provisions requiring the disclosure of internal transfer price (ITP) information by those gentailers.

1.3. The objectives of the proposal are to promote competition in, and the efficient operation of, the electricity industry for the long-term benefit of consumers by:

(a) ensuring the even-handed supply of risk management contracts, which supports the liquidity and competitive pricing of risk management contracts, and

(b) giving confidence to independent generators and retailers that they can compete on a level playing field with gentailers, which will encourage investment in the electricity industry.

1.4. The proposed amendment would do this by:

(a) reducing the risk of any withholding of access to shaped hedges, and other hedge contracts traded over-the-counter, including through increased monitoring of disclosed reasons for no offers or non-conforming offers

(b) reducing the risk of any discrimination in the pricing of hedges and any potential for anti-competitive retail margin squeezing by the four large gentailers. This would be done by introducing a new Retail Price Consistency Assessment (RPCA) that seeks to make transparent any differences between hedge prices and the expected cost of supply gentailers use in setting retail prices.

1.5. Section 39(1)(c) of the Electricity Industry Act 2010 (Act) requires the Authority to consult on any proposed amendment to the Code and corresponding regulatory statement. Section 39(2) provides that the regulatory statement must include a statement of the objectives of the proposed amendment, an evaluation of the costs and benefits of the proposed amendment, and an evaluation of alternative means of achieving the objectives of the proposed amendment. The regulatory statement is set out in Chapter 12 of this paper.

How to make a submission

1.6. The Authority's preference is to receive submissions in electronic format (Microsoft Word) in the format shown in Appendix C. Submissions in electronic form should be emailed to levelplayingfield@ea.govt.nz with "Consultation paper feedback" in the subject line.

1.7. We strongly encourage submitters who previously submitted on the LPF Options paper to focus their submissions on the novel elements of the proposals in this paper. We are particularly interested in submissions that engage with new information and analysis, or where the submitter has a new perspective or has changed their view on a matter. We discourage submitters from simply reiterating their previous submissions. It is enough to refer back to your previous submissions, rather than re-stating them.

1.8. If you cannot send your submission electronically, please contact the Authority on levelplayingfield@ea.govt.nz or 04 460 8860 to discuss alternative arrangements.

1.9. Please note the Authority intends to publish all submissions it receives. If you consider that the Authority should not publish any part of your submission, please:

(a) indicate which part should not be published,

(b) explain why you consider we should not publish that part, and

(c) provide a version of your submission that the Authority can publish (if we agree not to publish your full submission).

1.10. If you indicate part of your submission should not be published, the Authority will discuss this with you before deciding whether to not publish that part of your submission.

1.11. However, please note that all submissions received by the Authority, including any parts that the Authority does not publish, can be requested under the Official Information Act 1982. This means the Authority would be required to release material not published unless good reason existed under the Official Information Act to withhold it. The Authority would normally consult with you before releasing any material that you said should not be published.

1.12. Please also note that the Authority may also share submissions (including any parts that the Authority does not publish) with other public sector organisations, the gas industry body or an overseas regulator in accordance with section 47A of the Act. The Authority would only do so if the submissions could assist that organisation in the performance of its functions and if it was satisfied that there were appropriate protections in place for maintaining confidentiality.

When to make a submission

1.13. Please deliver your submission by 5pm on Tuesday 25 November 2025

1.14. Authority staff will acknowledge receipt of all submissions electronically. Please contact the Authority on levelplayingfield@ea.govt.nz or 04 460 8860 if you do not receive electronic acknowledgement of your submission within two business days.

2. Background and context

2.1. The Electricity Authority Te Mana Hiko (the Authority) and the Commerce Commission Te Komihana Tauhokohoko (Commission) jointly established the Energy Competition Task Force during a period of sustained high wholesale electricity prices in August 2024, during which there were significant fuel shortages. The Task Force, with the Ministry of Business, Innovation and Employment (MBIE) as an observer, is focused on short- to medium-term actions to improve the performance of the electricity market.

2.2. The Task Force's work programme focuses on two overarching outcomes:

- Package One — enabling new generators and independent retailers to enter and better compete in the market
- Package Two — providing more options for end users of electricity.

2.3. Package One of the Task Force's work programme contains four initiatives that focus on improving competition in the electricity industry. The Authority published the LPF Options Paper in February 2025 to progress two Task Force initiatives under Package One:

- Prepare for virtual disaggregation of the flexible generation base (also known as Task Force Initiative 1C)
- Investigate Level Playing Field measures such as non-discrimination rules (also known as Task Force Initiative 1D).

2.4. The LPF Options Paper offers an extensive chapter that outlines all the context and issues that led to the development of that paper.

2.5. Just before the publication of the LPF Options Paper, the Government announced the appointment of Frontier Economics as the lead in an independent review of the performance of the electricity markets. Frontier's report, along with the Government response, were released on 1 October 2025. Frontier recommended a different approach to improve third party access to firming than the non-discrimination approach. While the Government agreed with Frontier that "the non-discrimination measures will not address the underlying problem of a lack of new firm capacity in the market", the Government's view was that "the non-discrimination measures complement [other] actions to improve security of supply".[5]

2.6. The proposals in this paper are part of a broader package of changes to improve the operation of the electricity market, including:

(a) Strengthening trading of the super-peak standardised flexibility product (introduced in January). The consultation on those options closed on 30 September 2025.

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[5] "Key Frontier recommendations and the Government's response", New Zealand Government, accessed 1 October 2025, https://www.beehive.govt.nz/sites/default/files/2025-10/Frontier%20Recommendations%20and%20Government%20Response.pdf

(b) An upcoming review of market making in the electricity futures to strengthen price discovery and promote healthy competition, to be published in November.

(c) The potential development of other hedge products as the market evolves.

2.7. The Authority received over 40 submissions on the LPF Options Paper. The Authority also contacted all submitters and offered a confidential meeting to discuss their submission with the Authority. Over 20 submitters took up this offer. We have carefully considered all submissions and feedback and thank submitters for their considered contributions.

2.8. This paper provides a thematic response to key points raised by submitters to explain our proposals. It is not intended as a complete summary of submissions or a response to all points raised by submitters.

2.9. Where we have sought to summarise a particular submission, this has necessarily been carried out at a high level. Accordingly, the summary provided may not carry all the nuance associated with a submitter's view. The full submissions are available on the Authority's website.[6] A table listing all submitters is contained in Appendix D.

6 Electricity Authority, "Level playing field measures", (Feb 2025) https://www.ea.govt.nz/projects/all/energy-competition-task-force/consultation/level-playing-field-measures/.

3. Problem definition

3.1. The purpose of this chapter is to reconsider the problem or risk that the Authority is responding to, in light of the substantial submissions received by the Authority on the problem definition set out in the LPF Options paper. The defined problem or risk informs whether there is a case for regulatory intervention and, if so, the nature and shape of that intervention.

3.2. While there has been some change to our understanding of the problem definition, the Authority's view remains that access to, and pricing of shaped hedges still indicate there is a material risk of harm to competition (and so to consumers, including industrial consumers) that it should respond to. The Authority is particularly concerned that this risk is impacting on the confidence of new entrants and participants looking to expand in both the retail and generation markets.

Risks to competition and confidence in the market outlined in the LPF Options paper

3.3. In the LPF Options paper, the Authority expressed concern about the "risk that the combination of gentailer vertical integration and their control of flexible generation is hindering competition in generation and retail, and investment in new electricity generation." The paper noted that gentailers own the key flexible generation assets used to ensure electricity supply during peak periods.

3.4. As context for these concerns:

- Independent retailers had complained about gentailers allegedly refusing to supply shaped peak and super-peak products, and margin squeezes.
- Independent generators expressed concerns about access to and the price of firming they seek for power purchase agreements.
- There is increasing price volatility and demand for risk management products, relatively less flexible resource to back hedge contracts, and constrained ability to expand flexible resources in the short and medium term.

3.5. The evidence in front of the Authority at the time, set out in the *Reviewing risk management options for electricity retailer – issues paper* (RMR), pointed to scarcity being a driver of limited access to shaped hedges. But the RMR also recognised "…a plausible driver that has competition implications, e.g., 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."

3.6. In the face of competition risks regarding the availability and pricing of shaped hedge contracts, we considered that "[t]he onus is on the Authority to respond accordingly, to address potential competition issues, and promote generation and retail competition to deliver better performing markets for consumers". This was because in the short to medium term competition risks may impact the expansion of independent retailers and the entry of new generators. The supply of hedge contracts also has a material impact on the financial risk management of industrial customers.

3.7. This approach reflected the Authority's view that current mechanisms to mitigate the competition risks – such as disclosures of internal transfer prices introduced in response to an Electricity Price Review recommendation, the voluntary code of conduct for OTC trading, and discipline provided by technical substitutes for super-peak contracts – are not providing the necessary assurances to new generators and independent retailers that they can compete on a level playing field.

3.8. The Authority received a substantial volume of submissions on the problem definition. Submissions focused on several dimensions of the problem definition, including:

- Whether there is a hedge-related competition risk:
  - Are shaped hedges overpriced?
  - Is access to shaped hedges limited (for reasons other than scarcity)?
  - Are there enough substitutes for shaped hedges that super-peak access/pricing issues have no practical impact?
  - Is there evidence of a margin squeeze (noting that gentailers sell services in both wholesale and retail markets)?
- Whether there are indicators of an associated market power problem affecting incentives to invest in generation.
- If there is hedge-related competition risk, to what extent is vertical integration part of the problem?

3.9. Some submissions also argued that the paper was focused on the wrong problem.

Our current view on the problem definition – summary

3.10. Submissions led us to undertake further testing of the problem definition. We conducted further work on:

- pricing of super-peak hedges, given known and acknowledged gaps in our information on risk premia
- access to super-peak hedges, given alternative explanations offered for non-responses to requests
- substitutes for super-peak hedges, to further test whether other products could achieve similar risk reduction if super-peak hedges were not available or were perceived as overpriced
- whether the apparent lag in investment in new generation could reflect a strategy by existing market participants to hold up electricity prices
- retail margin squeeze, given concerns that gentailers' retail pricing may not reflect the cost of supply.

3.11. Based on this additional data and analysis, the Authority's current view is that:

- There is likely a lower risk that the price for super-peak hedges reflects a premium above competitive pricing levels, noting that the scarcity premium is likely non-linear, and rises 'disproportionately' at times of scarcity.
- Our previous concerns around access to hedges have not been substantially disproven.

- Peak hedges remain potential substitutes for super-peak hedges, but this is largely theoretical as the market for peak hedges is so thin that they are unlikely to currently be a practical substitute. Other substitutes for super-peak hedges exist but it will likely be several years before they are available in quantities needed to provide competitive discipline to the prices of shaped over-the-counter (OTC) hedge contracts.
- We have neither found nor been provided with any substantial evidence that the apparent lag in investment in new generation reflects a coordinated strategy to raise electricity prices. The long period of relatively limited electricity demand growth, the sequence of gas supply shocks and uncertainty about future gas supply, and uncertainty over the Tiwai contracts are more plausible explanations for the investment profile. A significant proportion of new generation in the pipeline is being advanced by independent parties.
- There is no definitive evidence of a margin squeeze, though nor has it been definitively disproven – for example some retail price offers were below wholesale contract prices in 2023.

3.12. Fuel or capacity scarcity is often the driver of limited access to, or high prices of, shaped hedge contracts, but we still cannot rule out the exercise of market power as a contributing factor to those prices.

3.13. While there has been some change to our understanding of the problem definition, the Authority's view remains that there is still a material risk of harm to competition that it should respond to. We observe thin and illiquid hedge markets with poor access to peak and super-peak hedges. While the lack of hedge contracts may not be the result of anticompetitive intent, it may be having anticompetitive effects. Some independent retailers have been avoiding new customers because they lack commensurate hedge cover and are unable to obtain it on terms that would allow them to serve these new customers. One of the gentailers also raised concerns about hedge availability for independent retailers.

3.14. In the short to medium term, risks to competition are likely to worsen because of fuel issues, an increase in the proportion of intermittent generation,[7] and increasing concentration in the ownership of flexible generation. The risks to competition may, however, reduce in the longer term as battery storage and demand side responses reduce the need for flexible generation to manage demand peaks.

3.15. While the evidence of anti-competitive conduct remains inconclusive, the risk of such conduct may weaken some market participants' confidence in the competitiveness of the market. Both the price and availability of key wholesale inputs, as well as confidence in those prices and availability, have the potential to damage competition in retail markets. The promotion of competition for the long-term benefit of consumers requires that participants can have confidence that they can compete on a level playing field when they invest in generation and retail businesses. The importance of

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[7] Where a rising proportion of generation demand is being met by intermittent generation, such as solar and wind, this increases the need for flexible generation to ensure sufficient capacity at peak times or dunkelflaute (periods when there is neither sufficient wind nor sunshine to power intermittent renewable generation).

confidence is a core reason for the Authority taking a risk mitigation approach to level playing field concerns.

3.16. The Authority is proposing proportionate measures to reduce the risk that market power can be exercised to increase the price and limit the availability of risk management contracts. The measures are designed to provide an opportunity for gentailers to provide assurance to stakeholders that they are transparent and even-handed when trading generation capacity. The Authority's view is that this will promote competition in, and the efficient operation of, the electricity industry, for the benefit of consumers. These proposals are outlined in detail in the following chapters.

3.17. The revised proposal specifically seeks to reduce the risk that it undoes the benefits of vertical integration. While vertical integration is a core part of the context within which these concerns arise, in the Authority's view it is not by itself the problem, and undoing vertical integration would at this point be a poorly targeted response to the nature and level of concerns we have.

3.18. The rest of this chapter provides more detail on each dimension of the problem definition, including summarising key themes from submissions.

Pricing of risk management contracts

3.19. We have focused our analysis on the pricing of super-peak hedges, as the RMR found that prices for ASX baseload, and OTC baseload and peak hedge contracts were likely to be competitive. In the RMR, the Authority could not conclude the same for super-peak prices. During the period covered by the RMR, super-peak prices tended to trade at prices well above benchmark prices of ASX baseload plus a shape premium.

Submissions

3.20. Octopus Energy (p4) submitted "that there seem to be unjustified risk premiums to products traded well in advance."[8] Pulse Energy (p2) agreed with the Authority's previous finding that we cannot conclude the prices for super-peak hedge contract are competitive. Mercury (p1) agreed there may be an issue with access to competitively priced risk management products, and supported the broader objectives of improving liquidity, competitive pricing and even-handedness.

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[8] Octopus Energy illustrates its concern by comparing a measure of near-term ASX prices to a long-range spot price forecast (p4). It suggests that, because ASX prices are closer to the 95th percentile of the forecast instead of the median, there seem to be unjustified risk premia, and that this reflects the exercise of market power held by the four major gentailers. The Authority does not consider such a conclusion can be drawn from this presentation – the near-term ASX prices fall within the confidence intervals the forecaster placed around its base case spot price forecast, meaning the forecaster considered there was a probability that its forecast spot prices could be higher than ASX prices. Furthermore, the Authority had tested ASX prices and found them to be unbiased estimates of future spot prices and thus likely consistent with workable competition (Appendix A of RMR), rather than containing unjustified risk premia. Our concerns about pricing relate to OTC super-peak prices.

3.21. Other submissions pointed to scarcity – uncertain gas supply and low hydro storage – as being the cause of high contract prices, rather than vertical integration or exercise of market power (for example Genesis, Meridian, the Mercury Panel).[9]

3.22. Meridian's advisors NERA considered it was more accurate to say the Authority's analysis was incomplete, rather than inconclusive, as four of the six premia had not been accounted for in imputing competitive super-peak prices.

3.23. Contact submitted that problems quantifying the super-peak premium should not be interpreted as a problem with the market. It considered a comparison of super-peak pricing to a price that would justify new [flexible] generation investment may be a better metric.

3.24. Contact also submitted other reasons why its prices did not reflect the exercise of market power: it was not reasonable to assume that it has market power, given it has only 10-14% of the flexible generation capacity, and it is a price-taker. It noted the Task Force had not found evidence of co-ordination (p12) and that the Task Force's own analysis shows there are substitutes capable of constraining prices (p13).

3.25. Sapere, on behalf of Genesis, submitted that flexible generation is owned by four competing entities and that the Authority has not shown that they any have substantial and sustained market power to foreclose a rival.

3.26. Meridian followed up with suggestions to improve the Authority's estimates of its benchmark (ASX baseload plus shape premium) to test the competitiveness of super-peak prices. These are outlined in Appendix E. Meridian also noted it had updated its pricing methodology in 2023 and, in its view, its offer prices are now very close to the benchmark used by the Authority.

Our response

3.27. The Authority agrees, as stated in the RMR paper, that fuel or capacity scarcity was often the driver of limited access to, or high prices of, shaped hedge contracts.

3.28. We agree that the significance of any unexplained super-peak premium must be considered in the context of the stated limitations in our methods. One such limitation continues to be that the method does not capture the non-linear nature of the scarcity premium. Consistent with the shape of wholesale market offer curves, the scarcity premium is likely non-linear, i.e. it rises 'disproportionately' at times of scarcity.

3.29. Our updated analysis indicates that:[10]

- There is often a reasonable degree of alignment between offered super-peak prices and the baseload + shape premium benchmark for Meridian and Contact:
    - most of the high-priced offers made by Meridian and Contact were requested between 5 and 7 months in advance
    - three quarters were for contracts equal to or less than a month

[9] A panel of experts commissioned by Mercury.

[10] Using data submitted to the Authority.

  - market conditions also played some part as some of the requests were made at times of declining hydro storage conditions and when the Ukraine war impacted fuel cost

- Since late 2023, after Meridian updated its methodology, its offer prices are very close to our competitive benchmark.
- The standardised super-peak product has improved availability and pricing, but the market remains shallow.
- Mercury's super-peak contract prices are often at a premium. We note though that:
  - this likely reflects to some extent that Mercury almost always offers, even when facing capacity constraints
  - recent data on standardised flexibility product transactions indicate Mercury's prices are in line with other transactions.

3.30. We undertook further analysis of super-peak pricing to address Meridian's methodological suggestions (see Appendix E). These suggestions created more points where contracts were priced lower than our competitive benchmark. This indicates a slightly better alignment between OTC offered contract prices and our competitive benchmark.

3.31. The Authority remains of the view that the exercise of market power may be an additional contributing factor to high super-peak prices, but the relative contributions of market conditions and any potential exercise of market power cannot be conclusively determined. In aggregate our updated analysis has closed some information gaps or better explained some premia, but it has not removed the risk identified in the RMR, i.e., we cannot rule out the exercise of market power as a contributing factor to these high prices. We still see the risk of exercise of market power as material.

Access to risk management contracts

3.32. Access to hedging is a critical input for independent generators, independent retailers as well as large commercial and industrial consumers. The RMR had identified concerns about access to super-peak hedges.

Submissions

3.33. Submissions offered mixed perspectives on whether access to hedging was a problem for independent generators and retailers:

- Consumer NZ and the IER observed that on some occasions, more than one independent retailer has sought to limit their visibility on Powerswitch to avoid gaining new customers. This is because they lacked hedge cover to service new customers.
- Helios said that they had first-hand experience of a lack of access to reliable shaped hedge contracts.
- Mercury agreed with the Task Force that there may be an issue for independent retailers accessing shaped hedge products.

- Sapere – as part of the Mercury panel – agreed that contract markets are not working as expected because a significant portion of the market seems to be choosing to be uncontracted. Three of the large gentailers are also often choosing not to offer on all contracts. Gentailer withholding could be explained by the gentailers also being exposed to the scarcity of physical hedges for super-peak periods.
- According to Sapere, there is no rational anti-competitive basis for withholding of contract prices: doing it for a retail price squeeze will not work, as (with free entry) the gentailer cannot expect improved profit in retail to last long enough to make up for foregone revenue, and even if the gentailer has a strategy to defer generation it is still valuable to write contracts. But Sapere was uncertain as to why gentailers do not still make offers at very high prices and believe this can only be explained by risk aversion.
- Carlson (as part of the Mercury panel) was concerned about anecdotal claims that independent retailers have difficulty accessing hedge markets at times of market stress. In their opinion, participants should not be seeking hedge cover during periods of market stress but rather to adjust positions they already hold. Different parties will have different hedging strategies, but parties need to hedge themselves in advance of unexpected events occurring, rather than during. There is a moral hazard in addressing such situations as it doesn't reward early and prudent hedging.
- Carlson also pointed out that the ASX peak product is only available for quarters and is not actively traded ie there is near zero liquidity and depth.
- Meridian contested the evidence base for the Authority's claim in the LPF Options Paper that a plausible driver of the prices of OTC super peak hedges was gentailers "refusing to supply products on appropriate terms to counterparties who are downstream competitors". Meridian noted its general practice is always to respond to RFPs from independent retailers. Our response

3.34. Neither submissions nor further analysis of responses to requests for hedge products altered the RMR conclusion that:

> "while evidence points to scarcity it did not definitively show why some gentailers sometimes elected not to respond to requests for proposals for shaped hedges or why some gentailers provided non-conforming responses."

3.35. Having analysed confidential information held by the Authority, we note that requests for super-peak hedges receive at least one offer per request, and at least one conforming offer around half the time.

3.36. Non-conforming or no responses to requests for super-peak or other hedge products do not necessarily indicate anticompetitive conduct – it may reflect a lack of capacity, for example because a vertically integrated business is fulfilling their prior commitments to supply their own retail or wholesale customers.

3.37. Even so, limited access and the lack of transparency on the reasons for no or non-conforming responses may impact market efficiency and contributes to a lack of confidence that competition is on a level playing field.

3.38. Chapter 55 addresses options for improving expectations and transparency around how gentailers respond to requests for hedge products and how these decisions are made. These options are intended to improve market liquidity and price discovery, to increase confidence.

3.39. Finally, we note Meridian's view that we have inaccurately described the extent to which they respond to RFPs. We acknowledge that our wording in the LPF Options paper could have been more precise but disagree with Meridian's underlying point.

3.40. Our analysis shows that Meridian responded to 85% of the 350 requests that they received and made offers on 65% of them. 40% of the requests received conforming offers. If we adopt Meridian's definition and extend the analysis to request IDs, rather than each product within the request, we can say that they almost always respond. When grouping by overall request IDs (considering a response to any product within the request as a response to the request) then Meridian made an offer for 96% of them. In our view, offers and particularly conforming offers for a specific product are the more useful measure for assessing hedge market liquidity than the somewhat arbitrary question of responses to overall requests.

Substitutes for risk management contracts

3.41. Given the RMR finding of potential issues with pricing of super-peak hedges, we have focused our analysis on substitutes for super-peak hedges.

Submissions

3.42. Only two submitters discussed substitutes for super-peak hedges. CSA for Meridian said that the prices of super-peak hedges are unlikely to materially impact an independent retailer's profit as they only provide minimal extra coverage compared to peak and baseload hedges, which are competitively priced. If there were an issue with super-peak hedges being materially overpriced, there is an arbitrage opportunity that retailers would already be taking advantage of. As speculative activity is not happening this suggests that they are competitively priced.

3.43. NERA for Meridian reiterated the RMR finding that a portfolio of base+peak is a substitute for base+peak+super-peak, suggesting that the impact of any anti-competitive behaviour on super-peak prices would not be competitively significant.

Our response

3.44. A core aspect of the complaints about the hedge market was limited access to super-peak contracts. Its impact depends on the availability of substitutes.

3.45. We analysed additional scenarios to those in the RMR to further test substitutability (via the impact of a 5% increase in price of super-peak hedges on spending on different hedge portfolios).[11]

[11] The modelling does not control for whether substitutes are available. The approach is based on the SSNIP test which seeks to identify whether a firm with market power could profitably impose a 'small but significant and non-transitory increase in price'. Our purpose here is to test whether purchasers would substitute to other products.

3.46. The RMR found a 5% increase in the price of super-peak products reduced spending on that product and increased spending on alternative portfolios such as ASX baseload plus peak, plus cap (C300) or plus battery services.

3.47. A similar pattern to those in the RMR was found under additional scenarios that assumed more intermittent generation, higher spot price volatility and higher prices at super-peak times. See Appendix F for details of this analysis.

3.48. Our additional analysis confirmed that there are potential substitutes under a range of scenarios – to the extent substitutes are available. There are alternative hedge/risk management portfolios with similar risk reduction effects at broadly similar cost. Even where alternatives are not perfect substitutes, they still provide risk management and help constrain any exercise of market power.

3.49. We also note that emerging technologies may provide alternatives to financial risk management products in the longer term. The future is likely to bring an increase in electricity demand and more intermittent generation. The Market Development Advisory Group (MDAG) report, *Price discovery in a renewables-based electricity system* noted that flexibility is the 'secret sauce' that will make the system work. In the future, they predict that this flexibility is likely to come from:

- the hydro system
- new (or repurposed) flexible generation sources, which may utilise biofuels
- batteries[12]
- demand side flexibility could also reduce the size of peak demand but will take time to implement at scale. MDAG project that flexible demand (as a percentage of total demand) would increase from 8% to 18% by 2035 and reach around 25% of total demand by 2050.

3.50. There are likely to be sequencing issues in the introduction of these new technologies, as well as lumpiness. We cannot definitively offer a view on their effectiveness as substitutes for risk management products, in the future electricity system.

3.51. The introduction of the standardised super-peak flexibility product earlier in 2025 has improved the availability and pricing of super-peak hedges on the OTC market, though this market is not yet sufficiently deep or liquid.[13] More broadly, as the Authority had noted though, alternative options are only starting to be deployed in the New Zealand market, so it will likely be several years before they have a significant discipling effect on the prices of shaped OTC hedge contracts. The risk of exercise of market power in the hedge market remains in the short to medium term. Technologies that shift demand over the course of the day are also not useful for

[12] The investment pipeline indicates a material amount of battery investment in the pipeline, with 377MW committed and over 3,000MW indicated to be commissioned by 2030, the majority by independent developers.

[13] Electricity Authority, "Regulating the standardised super-peak hedge contract: issues and options, Consultation paper", 19 August 2025, 2, https://www.ea.govt.nz/documents/8199/Regulating_the_standardised_super-peak_hedge_contract.pdf.

extended periods of scarcity. We remain concerned that viable substitutes are not currently available at scale.

Margin squeezing

3.52. The LPF Options paper noted that independent retailers had raised concerns about margin squeeze. The concern is that gentailers' practices are leaving independent retailers with insufficient margin to be able to compete with gentailers, by:

- using their market power to limit access to super-peak hedges or offer these at above competitive prices, as discussed above, or
- setting retail prices in the downstream market too low for non-integrated rivals to compete, if not below cost (which could amount to predatory pricing).

Submissions

3.53. Submissions expressed opposing views on whether margins were being squeezed.

3.54. Some submitters considered margin squeezing was occurring or expressed concern about its possibility.[14] For example, Independent Electricity Retailers (IER) submitted that retail prices have been below wholesale prices and that independent retailers have difficulty accessing hedges.

3.55. Link Economics for IER and Pulse Energy pointed to falling rates of retail switching and independent retailers' flat retail market share since 2021 as evidence of anticompetitive conduct. There have also been reports of some retailers suspending active recruitment of new customers for a time given their concern about access to and prices of hedges.

3.56. Link Economics compared survey data on average residential retail prices (less network costs) to ASX baseload contracts for all maturities[15] and concluded "baseload prices had been above the level of the retail price for a significant portion of the past three years." The Authority replicated this chart (Figure 1) which highlights the impact of rising contract costs on average margins from 2021.

3.57. Gentailers and the Mercury panel disagreed with the claim of (anti-competitive) margin squeezing. These submissions did not agree that gentailers had the ability or incentive to do so, or that the evidence supported such claims.

3.58. Contact, Sapere for Genesis and Energy Resources Aotearoa, for example, argued that, with four large gentailers competing, it would be difficult for any to exercise market power to raise rivals' costs or to raise retail prices after rivals have exited to recoup losses incurred during any predatory pricing.

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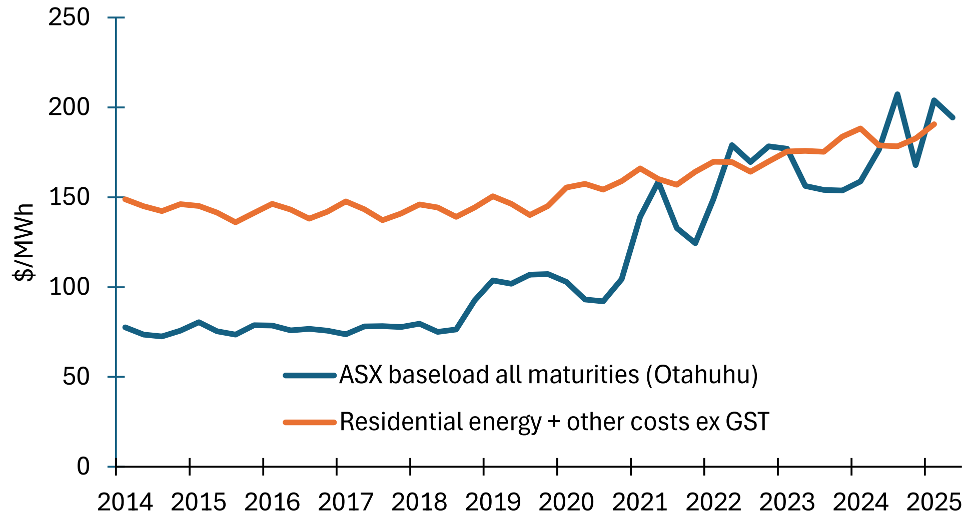
[14] See 2degrees, Helios, Geoff Henderson, Independent Electricity Retailers, Lodestone, Pulse Energy, Total Utilities.

[15] Link Economics' original chart labels these as long-dated contracts, which seems a typo. The value of long-dated contracts is somewhat lower, though using that series does not alter the substance of their submission.

Figure 1: Residential energy + other costs compared to baseload supply cost



Source: MBIE Quarterly Retail Sales Survey and emi.ea.govt.nz

3.59. Sapere for the Mercury panel concluded from its analysis of margins in selected network areas that gentailer margins are lower than those of other retailers, but are not, on average, below cost. It also noted that if there has been predatory pricing it has not been successful, because collectively small and medium retailers remain a significant competitor to the large gentailers.

3.60. Different explanations were put forward for the lagging of average retail prices to the cost of supply and thus reducing margins. Sapere for the Mercury panel suggested low margins are consistent with competition. It also considered that insulating retail customers from short run market impacts, through averaging variable costs over a few (five) years, is a service valued by customers.

3.61. CSA for Meridian pointed out that there had been ‘considerable price-smoothing’ over the 2018-2024 period. This seemed to reflect an expectation (that has not panned out) that wholesale prices would revert to or fall below pre-2018 levels in real terms after two to three years.

> “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.”

3.62. CSA submitted that the period of high wholesale electricity prices turned out much longer because of a sequence of large adverse supply and demand shocks – “retailers have probably provided deeper and longer price smoothing than they would have done if they had perfect foresight”. Without smoothing CSA estimates retail prices could have been over 20% higher in 2024.

3.63. Contact similarly noted that “mis-forecasting the permanence of the wholesale market price change” has played a role in retail prices lagging costs, as well as the role of regulatory attention.

Our response

3.64. Margins have reduced as retail offers have not kept pace with the cost of supply. However, this is not in and of itself evidence of anti-competitive margin squeezing. Nor are the changes in market share or switching rates. Nevertheless, the Authority is aware of these trends and wants to be assured that they reflect competitive dynamics in challenging market conditions, rather than the outcome of anti-competitive conduct. This is also important to give confidence to independent generators and retailers that they can compete on a level playing field with gentailers.

3.65. Predatory pricing currently requires some prospect of recouping lost revenue. In our view, predatory pricing is unlikely in the electricity sector. Raising rival's costs, through high hedge prices, is a more likely avenue for margin squeezing. Anti-competitive margin squeezing is difficult to detect. One reason is that falling margins may reflect the desirable effects of competition, benefitting consumers through lower prices.

3.66. Uncertainty is another reason that margin squeezing is difficult to detect. Retail electricity prices set today reflect expectations of the future – about expected costs of supply,[16] about market conditions, and the strategies of competitors.[17] At the end of the year, reported margins could be small or negative because retailers' expectations at the beginning of the year turned out to be wrong, or their historic hedging positions were poor. And, as some submissions noted, there could be a sequence of such errors.

3.67. Further, as retailers invest in their brand or compete to retain or build their customer base, they may look through short term periods of scarcity (or abundance) in setting retail prices. That is, retail prices not only reflect expected cost of supply, but also wider considerations such as market share objectives, customer churn, the firm's overall portfolio, and competitor behaviour.[18]

3.68. In other words, there are good reasons for retailers to smooth out wholesale market fluctuations and supply shocks in their pricing. This is a retail strategy that many consumers appear to value, and which is not anti-competitive.

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[16] This 'opportunity cost' framing was also noted by the Australian Competition and Consumer Commission in its 2018 Retail Electricity Pricing Inquiry Final Report, 125 https://www.accc.gov.au/system/files/Retail%20Electricity%20Pricing%20Inquiry%E2%80%94Final%20Report%20June%202018_0.pdf.

[17] This forward-looking expected (opportunity) cost of supply perspective on retail pricing differs from a backward-looking accounting profit perspective. For the latter, actual cost paid for supply and hedge positions built up over time are relevant. But expectations of where the costs of supply are headed over a period consistent with a retailer's strategy is economically relevant when setting retail price offers. This is because at the margin a gentailer is making a trade-off between on-selling electricity or recruiting the next customer. This is also consistent with what gentailers, and their experts submitted (see paragraphs 3.60-3.63). Contact submitted its internal transfer price is "an important input into retail pricing, but we must also take account of other input costs, and the market price…" Mercury bases its internal transfer price on a three-year outlook of baseload futures at Otahuhu plus adjustments to reflect profiling and locational prices where Mercury has a retail presence.

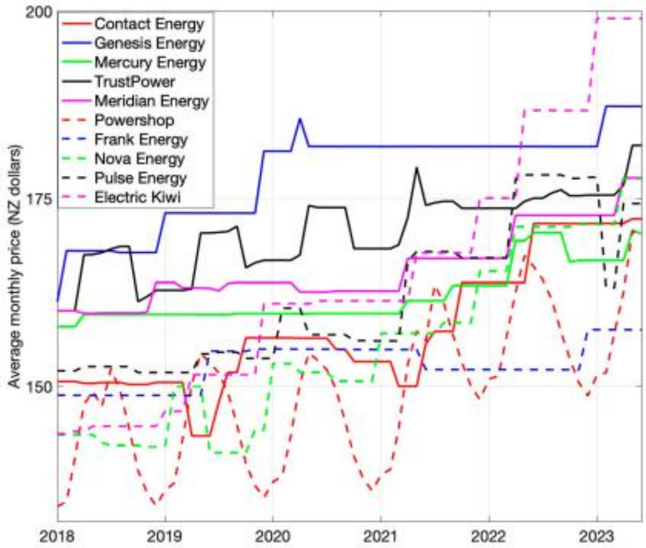
[18] Electricity Authority, "Internal Transfer Price and Retail Gross Margin post implementation review", Para 4.5-4.7, https://www.ea.govt.nz/documents/5981/RGM_and_ITP_post_implementation_review.pdf.

3.69. None of the above points are intended to indicate that the Authority would not be concerned about anti-competitive margin squeezing. On the contrary we would be deeply concerned if competition is being impeded by this kind of behaviour. But given the uncertainties and risks around measuring margin squeeze that we have noted above, we need to ensure that we identify anti-competitive conduct but avoid false positives. None of the analysis of margin squeeze in the submissions we received robustly demonstrated a margin squeeze in our view.

3.70. Noting that the presence or risk of margin squeeze has been persistently raised, but that none of the submissions provided a sufficiently robust analysis to prove this point one way or the other, the Authority drew on recently published research on retail pricing covering 2018-2023 to undertake a high-level screening assessment.[19] This is simply an indicative starting point for considering whether margin squeeze may have been occurring in respect of residential customers (and has more relevance in light of the Authority's revised proposal set out below).

3.71. Detailed Powerswitch data was used to construct estimates of retail offers by network reporting region for the 10 largest retailers by market share as at June 2023 (outlined in Figure 2). This covered the vast majority of connections.[20]

Figure 2: Monthly retail price offers by top 10 brands as at June 2023



Source: Gibbard & Grubb (2024), using Powerswitch data

3.72. Following Link Economics' approach, we subtracted estimates of network costs (included in the data set) from retail prices to get an 'energy cost + margin' measure. This measure still includes metering costs and levies, ~5% of retail prices.[21]

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[19] Peter Gibbard and Cameron Grubb, "Retail electricity prices in New Zealand: recent trends and the relationship to market shares,: *New Zealand Economic Papers*, 58:3, 288-298, DOI: 10.1080/00779954.2024.2339378. The data are published with the article as supplemental material.

[20] To manage the multiplicity of plans on offer, Gibbard and Grubb selected the most common plan per retailer per region for a standard household and calculated average monthly prices by brand implied by the offers. The national price measures are averages of each brand's regional price weighted by the number of ICPs.

[21] "Your Power Bill," Electricity Authority, accessed 1 September 2025, https://www.ea.govt.nz/your-power/bill/.

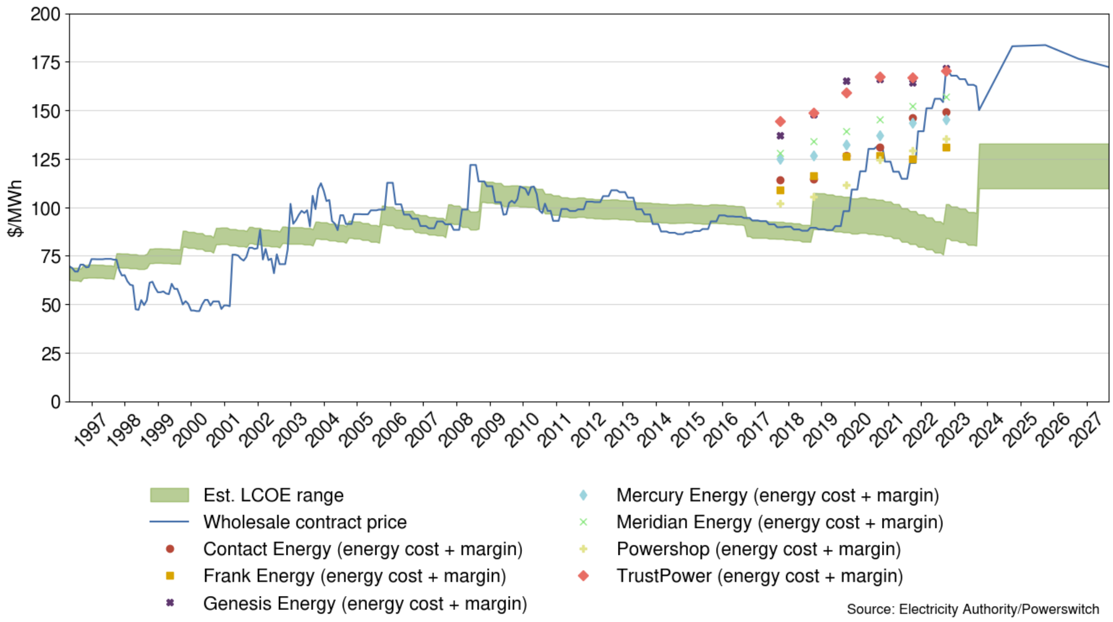
3.73. We compared these to two possible market-based measures of the cost of supply available to us:

- one year ahead futures prices, which look through very short-term volatility, though may be too short-term for setting retail price offers
- long run marginal costs, though this may be too long-term a measure for retail contracts.

3.74. A possible consideration for selecting an appropriate time horizon for the cost measure (besides each firm's wider considerations for retail pricing mentioned above, including the price risk management service that retailers may provide) is that customers tend to stay with a retailer for multiple years.[22]

3.75. To be clear, the Authority does not consider that short-term market conditions should drive retail prices, or that retailers cannot take a longer view of expected market conditions and insulate their consumers from short term movements.[23]

Figure 3: Gentailers' retail price offers (ex-network costs) and cost of supply



Source: Concept Consulting, Electricity Authority, and Gibbard & Grubb 2024

3.76. We would be concerned that retail prices were artificially low if our measures of 'retail prices less network costs' were persistently below expected wholesale market cost.

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[22] A retail switching rate of ~18% per annum implies a retail customer stays an average of ~5.5 years with a retailer (=1/.18). The majority of these are move-in switches, which may include loyal customers starting a new contract with the retailer they were with at their previous address. Only around 5-6% are trader switches, highlighting the general stickiness of consumers.

[23] Conversely, this does not preclude retailers from offering packages with greater price exposure to the market, such as Flick Energy's plan that allowed consumers to be exposed to spot price movements.

Over time, we expect our measure to be somewhat above supply costs, because gentailers will ultimately need to recover their cost of retailing.[24]

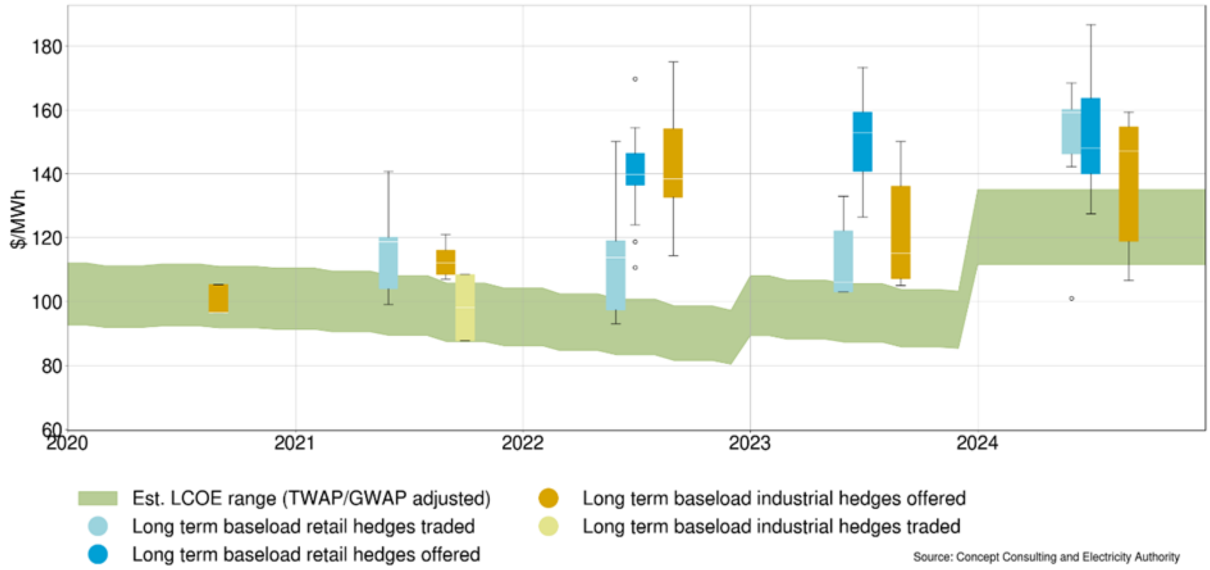
3.77. We did not find definitive evidence of margin squeezing between 2018 and 2023:

- Retail price offers for gentailers' main retail brands were above contract prices between 2018-2022, though they were close to or below contract prices in 2023 as one year ahead contract prices rose.
- Gentailers' discount brands – aimed at competing for the more price sensitive ('switchy') retail consumers – have more sharply-priced tariffs. These are closer to the year-ahead contract prices, and below them in 2023. We would be concerned if that became a trend.
- In both cases offers remained above levelised cost of electricity (LCOE), as a broad indicator of long run marginal costs.

3.78. As noted above, the Authority currently considers one year ahead prices are likely too short a measure of expected costs for retail pricing, whereas long run marginal cost may be too long.

3.79. Retail Gross Margin (RGM) data disclosed by independent retailers did not change this analysis. That data indicates that for 2022, 2023, and 2024, independent retailers' average annual electricity costs were below the median ASX traded price. This suggests that these retailers traded on the ASX at times when prices were lower or reduced their energy costs through other means, including longer term OTC hedges (trades with a duration of five years or more).

Figure 4: Long-term hedge prices retail and industrial (5+ years) and levelised cost of electricity



24 This approach reflects the 'as efficient competitor' method. It checks whether a competitor that is as or more efficient than a gentailer can profitably operate. But it does not provide an allowance for less efficient competitors, nor does it rely on identifying what an efficient cost might be.

3.80. This market-wide assessment is not definitive. It focuses on retail offers, which are most relevant for competition between retailers for the next customer.[25] But this does not consider the possibility that (during extended periods of rising costs) a large gentailer may keep its own retail prices 'too low' for existing customers, with the intent to harm competition, by dissuading existing customers from considering a switch.

3.81. Nor does it substitute for a detailed investigation of a potential breach of s36 of the Commerce Act 1986 that the Commission might undertake, if there were evidence supporting a potential breach of that Act.

3.82. Overall, we expect that different submitters will draw different conclusions from the data we have set out. Based on the above analysis, we do not consider that there is compelling evidence that a margin squeeze has been occurring. But we acknowledge that the general framework for a margin squeeze does exist here: concentrated suppliers in the upstream market; a degree of vertical integration; and retail margins lessening in recent years. Further, the complaints received by both the Authority and the Commission show that some stakeholders do perceive a margin squeeze is occurring, and that perception risks undermining confidence in the market. This provides a rationale for monitoring the consistency of retail prices with the cost of supply, using a clear framework and robust parameters. We outline a proposal for this later in the paper.

Generation investment and incentives

3.83. There is currently a gap between wholesale prices and LCOE, which indicates an imbalance between demand and supply. The time that it is taking for that gap to close is seen by some as being the result of generation investment being held back to keep generation prices high.

Submissions

3.84. Submitters often had opposing views on wholesale (spot and hedge) prices. Octopus, Fonterra, Major Electricity Users Group (MEUG), and IER said that ASX prices are not efficient as they have been elevated above long-run marginal cost (LRMC)[26] since 2018. The concern is that the disconnect between ASX futures pricing and forward spot price projections indicates unjustified risk premiums.

3.85. Meridian argued that the gap between short duration hedge prices and LCOE is not a useful indicator of competition concerns – it suggested (p20) that high thermal fuel costs rather than underlying competition issues are the primary driver of elevated ASX prices. It cited (p21) CSA for Meridian who note the comparison between short term contract prices and LRMC (or LCOE) is not like-for-like, because the latter are the average cost of energy over a plant's entire life. Elevated short term ASX

[25] The above analysis does not capture, for example, differences in offers by location, all forms of retail tariffs available, or special offers made by salespersons that are not necessarily posted on Powerswitch.

[26] We have used the (related) terms LRMC and LCOE interchangeably here as different submitters have used different terminology to express similar concepts. LRMC is the cost of expanding supply. This includes LCOE for the lowest cost mix of new generation plus the cost for firming that new generation.

contracts are not representative of the return on an investment over the investment's life.

3.86. Other factors were also raised as explanations for low levels of investment in generation and the divergence between LRMC and market prices, such as:

- uncertainty around Tiwai contracts (Nova, the Mercury panel, Energy Link, Sapere for Genesis, Concept as part of the Mercury panel)
- 100% renewable energy target (Nova)
- little or no demand growth (Energy Link)
- NZ Battery project (Sapere for Genesis, the Mercury panel).

3.87. Concept submitted that the current structural shortfall in generation capacity, which emerged in late 2018 has been driven by various factors. One was the sustained increase in thermal fuel costs. Another was the overly optimistic forecasts of gas production (dampening signals about the profitability to invest in generation).

3.88. Another factor raised by Concept was uncertainty about the future of Tiwai which also suppressed investment. If Tiwai had shut down in 2024, this would have led to a 13% reduction in electricity demand, with no need to build new generation.

3.89. Concept (p17) forecast that the system will be back in balance by the middle of 2030 with contract prices returning to LRMC-driven levels, and that by mid-2028 prices will no longer be significantly elevated above LRMC (though it notes current elevated ASX prices indicate the imbalance to persist into 2028).

3.90. There were a variety of views on current incentives to invest in generation:

- Sapere (as part of the Mercury panel) considered that "a strategy of anti-competitive withholding of generation investment is at best extremely hard to prove, and at worst not credible." Withholding security of supply investment would make most sense if a party had a credible peak investment that deterred competing projects and deferred their project as long as they could.
- Helios observed gentailers prefer to build their own renewable projects even if they are more expensive than contracting with independent generators.
- The IER disagreed that current market conditions are maintaining investment incentives. Incumbent gentailers have no incentive to expand output, wholesale prices are above LRMC, and lack of investment by gentailers has resulted in the current scarcity.
- Lodestone stated that discriminatory transfer prices impede incentives to build generation.

3.91. Other submitters highlighted other issues around investment incentives:

- Business NZ agreed that increasing competition in access to hedge contracts is important to support new generation investment.
- Lodestone posited that the proposals will not change generation build incentives for gentailers but would increase them for other market participants.

- Ecotricity urged caution to ensure the continued development of new renewables, as that supports competition and reduced wholesale prices over time, and reduced emissions.

3.92. Energy Link submitted that the cost of building, owning, and operating generation had increased 50-80% since 2020/21 and that this was a bigger issue for the bankability of projects than access to suitable power purchase agreements (PPAs). Costs may stymie the pace of investment. Contact also submitted that costs are materially higher than was presented in the LPF Options paper.

3.93. Sapere, as part of the Mercury panel, submitted that wholesale market prices have not been high enough for long enough to justify investment in low utilisation (that is, flexible) generation.

Our response

3.94. The gap between contract prices and the cost of new generation indicates an imbalance between generation and demand.

3.95. The LPF Options paper acknowledged this gap and noted some parties consider that the persistence of the gap reflects an anti-competitive delay in investment to hold up prices.

3.96. We agree with Concept's analysis of investment dynamics. Neither the current rate of build nor the observed pipeline of investment (including the significant portion from non-incumbents) is consistent with any gentailers profitably delaying investment. We will nevertheless continue to monitor the situation; our monthly updates to the generation pipeline enable us to observe the speed at which proposed projects come to fruition.

3.97. And, while investment in intermittent generation is now occurring at pace, we are concerned that investment in flexible generation or other forms of flexibility (such as batteries) is not occurring at an appropriately matched pace.

3.98. Noting Energy Link and Contact's submissions that development costs had risen, we updated our estimate of the LCOE, based on the costs of recent developments.[27] This is reflected in Figure 4.This new (and higher) estimate provides an updated foundation for further discussion.

Vertical integration

Submissions

3.99. There were extensive submissions on vertical integration in the electricity sector. Sapere (for Genesis) noted that it is the predominant organisational form in competitive electricity markets. A few submitters cited an Australian study that finds standalone peaking generation is 'unbankable'.

3.100. Submitters highlighted a number of benefits from vertical integration:

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27 The increase in construction costs since 2020 has been significant.

- provides a natural hedge (IER, Cognitus, Lodestone, NZ Steel, Sustainable Energy Association NZ (SEANZ), Electricity Retailers Association NZ (ERANZ), NERA)
- smooth price and volume volatility (MEUG, NZIER, Genesis, NERA)
- improves risk management (SEANZ, Lodestone, Genesis, Contact, NERA, the Electricity Engineers Association (EEA), Lodestone, Nova, Octopus, ERANZ)
- reduces transaction costs (Genesis, NERA, Contact, EEA)
- shields consumers from price volatility (Genesis, CSA, NERA, EEA, Meridian, SEANZ, ERANZ)
- incentivises investment (Genesis, NERA, Nova, Cognitus, Contact, EEA, Meridian, ERANZ, Unison)
- creates revenue stability (Genesis, Contact)
- more competitive wholesale pricing (Genesis, Contact)
- more retail competition and lower consumer prices (Cognitus, Contact, Meridian, Nova, Contact, Genesis, ERANZ)
- gentailers less likely to exercise market power than generator only businesses (Sapere for Genesis, Cognitus, NERA, Contact, Energy Link, Meridian, Nova, Electric Power Optimization Centre (EPOC))
- better operational data (EEA)
- easier to bundle (EEA)
- eliminates double marginalisation (Link Economics, Sapere for Genesis, Cognitus, ERANZ, Unison)
- efficient business model (Nova)
- easier demand side flexibility (Contact, EEA)
- increased innovation (EEA)
- maintain capacity in an energy only market (Energy Link)
- longer term outlook (Lodestone).

3.101. Consumer NZ, by contrast, were sceptical that vertical integration has delivered on its theoretical benefits. As evidence they cite rising retail prices, persistent market concentration, high entry barriers, stifled innovation, as problems, lack of consumer confidence, and a lack of transparency in the market. IER also questioned if any of the cited efficiencies from vertical integration are passed on to consumers.

3.102. Lodestone was of the view that vertical integration only works well if independent retailers are able to apply competitive tension over long periods of time, which requires rigorous regulatory oversight.

3.103. Submitters also noted competition concerns that arise from vertical integration. In some cases, these concerns were not separated out from competition issues arising from market concentration:

- preferential hedge access for gentailer retail functions (SEANZ, EEA, Energy Link, Helios)
- restricting market information (EEA, Helios)
- cross-subsidisation between generation and retail (EEA, Octopus, Energy Link, Helios)
- reduced innovation (EEA, Octopus, Consumer NZ)
- favouring own retail business (EEA, Helios, IER)
- disincentivising investment in generation (IER, Link Economics, Helios, Octopus, Lodestone)
- inefficient pricing of risk (Octopus)
- delayed or refused contracting (Octopus, EEA)
- lack of PPAs (Octopus, Helios)
- suppressing demand response (Octopus, Helios)
- barriers to entry in retail and generation (IER)

3.104. Contact stated that competition concerns with vertical integration are theoretical and are outweighed by consumer benefit. Genesis also criticised the LPF Options paper for its lack of quantitative or qualitative analysis that vertical integration is the root cause of insufficient peak hedge contracts. Nova expressed similar views.

3.105. Energy Link noted that independent retailers cannot compete effectively and have not grown since 2020. They had tended to drive innovation in retail space and put downward pressure on prices but are now hamstrung by hedge availability. Thriving independents should have more market share and should have gotten there sooner.

3.106. Submitters were asked if there are areas other than the hedge market where vertical integration and market power raise concerns. The following issues were highlighted:

- ability to lobby to prevent change (Common Grace, EEA)
- disproportionate influence on market rules (EEA)
- access to superior network, system and consumer data (EEA, Consumer NZ, Helios)
- limited price discovery and transparency in hedge markets (EEA)
- control of strategic connection capacity at key network nodes (EEA)
- management of hydro capacity (Geoff Henderson).

Our response

3.107. We agree that there are benefits of vertical integration, and that it is a legitimate business model – the LPF Options Paper was not seeking to contest that. Rather it raised questions about vertical integration based on the following logic:

(a) There is a competition risk associated with market power in the wholesale electricity market, specifically in relation to flexible generation.

(b) The complaints we have received, and which our own analysis could not dismiss, indicate that this competition risk is having an impact in the adjacent retail electricity market, at least in terms of retailer confidence in entry, growth and investment.

(c) The owners of the relevant flexible generation are vertically integrated and operate in both markets, including selling a key wholesale input to their retail competitors.

(d) The best long-term solution to the competition risks is for more flexibility (generation or otherwise) to be introduced into the wholesale and retail markets by a wider range of flexibility suppliers, as this would reduce the relevant market power and therefore any distortion arising from that power in all relevant markets.

(e) In the short to medium term, the Authority is considering how to mitigate the potential effect of that market power, particularly in the retail market, but also in relation to new intermittent generators that are seeking firming (to support power purchase agreements (PPAs)).

(f) In seeking to mitigate the potential effect of the gentailers' wholesale market power in an adjacent market, one important line of inquiry is the role of vertical integration in leveraging that market power into the retail market, and whether a remedy that directly addresses vertical integration would be the most effective mitigation.[28]

3.108. We agree with the general theme of submissions that to properly assess whether a vertical integration focused remedy is fit for purpose we must also consider the benefits of vertical integration.

3.109. On the question of the benefits to vertical integration, several submitters highlighted potential benefits not covered in the LPF Options paper:

- more competitive wholesale pricing, as gentailers are less likely to exercise market power than generator only businesses
- more retail competition, lower consumer prices and less consumer price volatility.

3.110. We agree with the evidence presented on vertical integration mitigating some effects of market power in the wholesale market, compared to generation only businesses. Multiple empirical studies from the US and Spain show that vertical integration is associated with less exercise of market power and wholesale prices closer to competitive levels, than generation-only businesses.[29] There is a similar empirical finding for the Australian NEM market.[30]

3.111. Theory suggests that vertical integration mitigates wholesale market power because a gentailer's natural hedge means that gains in the generation business are balanced

[28] The independent retailers have repeatedly expressed a view that vertical separation would be the most effective remedy, including in their submission on the LPF Options paper.

[29] Richard Meade "Review of the Economics Literature on the Pros and Cons of Vertical Integration and Vertical Separation in Electricity Sectors", October 2021, 20-21, https://www.cognitus.co.nz/_files/ugd/022795_90a6a69bdaca4de9b752db7798bf2a2d.pdf.

[30] Frontier Economics, "Effects of vertical integration on capacity bidding behaviour: A Report Prepared For Herbert Smith Freehills", August 2017, ("Frontier, Effects of Vertical Integration"), 2-3, https://www.accc.gov.au/system/files/AGL%20%28Frontier%20report%29.pdf.

by losses in the retail business. They face dispatch risk (bid too high and risk not having their generation dispatched, exposing their retail load to the spot price), and uncertainty in knowing the exact level of their retail demand until after the trading period. This is an important benefit that was not set out in the LPF Options paper.

3.112. We are less convinced about the claims of improved retail competition from vertical integration, given the risks to retail competition posed by vertically integrated businesses with market power, as outlined in the previous sections.

3.113. We also do not agree that less consumer price volatility is a function of vertical integration. It is more likely the result of large balance sheets. If a retailer is smoothing prices[31] and protecting consumers from higher-than-average wholesale prices, then they must also be recovering those losses by charging those consumers higher prices when wholesale prices are lower than average.

3.114. Claims about lower consumer prices or, more importantly, increased consumer welfare, are harder to analyse. To consider this, we have to take into account competition in both the retail and wholesale markets

3.115. Electricity market design involves a trade-off between wholesale and retail market competition. As outlined above, vertical integration potentially mitigates some market power in the wholesale market but can lead to competition problems in the retail market. Generation only businesses can more easily exploit market power in the wholesale market but are more likely to be associated with highly competitive retail markets.

3.116. We note both the benefits and risks of vertical integration. As the LPF Options paper pointed out “competition issues can arise where vertical integration is combined with market power”. Vertical integration can then enable wholesale market power to be leveraged into other markets. In our view though, the competition risks we have identified are not best mitigated by measures that effectively undo vertical integration.

3.117. As such, a full assessment of the costs and benefits of vertical integration is not required. Measures that simply separate retail businesses from wholesale businesses would be an untargeted and likely disproportionate response to the specific discrimination concerns in the short to medium term, and ineffective is reducing wholesale market power in the longer term.

3.118. Submitters raised a few costs or risks associated with vertical integration that had not been covered in the LPF Options paper. These were relatively minor (restricting information, reducing innovation) in comparison to the main issues that had been identified. We also note the issues raised about the risks outside of hedge markets.

3.119. The proposals in the following chapters are focused on mitigating the risk presented by the combination of wholesale market power with vertical integration. We are not proposing any measures that separate retail and wholesale businesses (either

[31] This smoothing is on a longer timeframe than smoothing the day-to-day volatility that any retailer is doing for any retail plan (other than spot + margin plans).

virtually or structurally), as they are unlikely to be the best response to the risk we have identified.

Some submissions considered LPF focused on the wrong problem

3.120. A number of submitters raised issues with the availability of flexible generation, including Genesis, MEUG, Energy Link, Energy Resources Aotearoa, the Mercury panel, SlowJam, 350 Aotearoa and Vector. Nova and the Mercury panel went further and expressed concerns about the increasing concentration of ownership of flexible generation. A number of submitters also raised concerns about constrained domestic gas supplies and the impact this has had on prices (Nova, the Mercury panel, ERANZ, Genesis, Meridian).

Our response

3.121. We agree that there are issues with the availability of, and incentives to build, flexible generation. We share concerns about the risks from increasing concentration in the ownership of flexible generation. Difficulties with flexible generation will be exacerbated by the growth in wind and solar generation. Interventions that directly address the availability of flexible generation are outside of the scope of this level playing field work (which has a specific discrimination focus) and are part of the Government's response to its review of electricity market performance.

3.122. We still consider though that the Authority should address level playing field concerns. Whether or not these concerns are the most pressing issue in the sector right now, resolving them will make a material contribution to well-functioning wholesale and retail electricity markets over time. Competitive markets provide opportunities for efficient entrants to compete, rather than advantaging incumbents with some level of market power. If the playing field risks being tilted, and that is impacting entry decisions and prospects, it should be addressed sooner rather than later. This approach is consistent with the Government's response to Frontier's report.

Questions

Q1. Do you have any comments on our additional analysis of data to inform the problem definition? Do you have any new evidence to add to any of the elements of the problem definition?

4. Level Playing Field options (options 1-4)

4.1. The purpose of this chapter is to review the different level playing field interventions available to the Authority, in light of submissions on the LPF Options paper, and the Authority's current understanding of the problem it is responding to. The LPF Options paper identified four options for addressing the competition concerns outlined in the problem definition:

- Option 1 – Accounting separation
- Option 2 – Non-discrimination obligations
- Option 3 – Negotiate-arbitrate regulation
- Option 4 – Corporate separation with arms length requirements.

4.2. Submissions to some extent added to that option set, though often with complementary measures rather than substitutes.

4.3. For the most part, submitters did not support Options 1 and 3, though a few suggested they could complement the other options. The independent retailers strongly favoured Option 4. Option 2 was favoured by a large number of submitters, though the gentailers proposed changes.

4.4. Submitters specifically engaged with two criteria when critiquing Option 2:

- impact on investment incentives
- risk of retail price rises - effectively an unintended consequence.

These received enough attention that we deal with them separately here.

4.5. After considering all the feedback, the Authority's view remains that Option 2 is the most suitable response to the competition risks identified. It is proportionate, appropriately targeted, and workable with some modifications to the February design. Our revised approach to Option 2 is outlined in the four following chapters.

4.6. We also emphasise that the proposed non-discrimination options are part of a broader package of measures to increase depth and liquidity in hedge markets, including:

- Strengthening trading of the super-peak standardised flexibility product (introduced in January). The consultation on those options closed on 30 September 2025.
- A review of market making in the electricity futures market to strengthen price discovery and promote healthy competition, which will be published in November.
- The potential development of other hedge products as the market evolves.

4.7. The following sections outline each option, the feedback received, and our response to that feedback. We have also separated out the feedback on retail price effects and incentives on generation investment.

Option 1 – Accounting separation

4.8. Accounting separation would require the financial accounts of a vertically integrated firm's business units (e.g. the generation and retail arms of a gentailer) be kept separate from one another. This is a form of information disclosure regulation and is aimed at promoting greater transparency in the performance of separate business units. Accounting separation would allow anti-competitive behaviour to be more readily identified, thereby disciplining the gentailer and assisting the Authority to monitor any potentially anti-competitive behaviour.

4.9. Submitters were generally sceptical of Option 1 increasing access to hedging products. Neoen, for example, argued Option 1 lacked enforcement mechanisms to ensure fair access to hedging products. The BusinessNZ Energy Council (BEC) broadly agreed, saying that while Option 1 might increase transparency and help identify price discrimination, it was unlikely to affect the pricing and availability of hedges for third parties. NZ Steel similarly believed that although Option 1 might bring additional scrutiny, it was unlikely to have any real impact.

4.10. We agree with submitters that, while Option 1 (accounting separation) would improve transparency, it is unlikely to deliver substantial benefit in terms of pricing or access. Implementing Option 1 would likely require the development of input methodologies for allocating costs between different business units. If so, Option 1 would be expensive with relatively little benefit.

Option 2 – Non-discrimination obligations

4.11. Non-discrimination obligations would require gentailers to offer external parties access to products (e.g. hedge contracts and firming) on substantially the same terms as the gentailers supply themselves internally. This would promote a level playing field between gentailers' internal business units and independent operators. It would also present a relatively low-cost method of mitigating the risk of discriminatory behaviour.

4.12. Option 2 was presented as the preferred option.

Feedback

4.13. Many submitters favoured or were at least broadly supportive of Option 2, including 2degrees, Centralines, Consumer NZ, Entrust, Fonterra, the IER, Lodestone Energy, the Northern Infrastructure Forum (NIF), Octopus Energy and Unison.

4.14. Submitters expressed a range of views on non-discrimination obligations. Contact supported Step 1 of Option 2 because they believe Step 1 is proportionate to the evidence, while others said Option 2 represented a moderate intervention that could be applied rapidly. Business NZ preferred Option 2 on the basis that it could be implemented quickly, would maintain gentailer flexibility of operations, and achieve some of the transparency goals of Option 1. EVA Marketplace similarly thought non-discrimination obligations combined with other measures could offer a reasonable balance between speed and cost to implement.

4.15. Some submitters, although generally supportive, did not believe non-discrimination obligations went far enough or were likely to address underlying issues. For example, MEUG argued that while Option 2 would give other market participants more equitable access to hedge products, it would not increase the supply of flexible firming generation in the market, which was urgently needed.

4.16. On a similar note, while the IER preferred non-discrimination obligations to the status quo, it did not think these were sufficient. In the IER's view, Option 2 would not address the market power problem discussed in the MDAG Report. Vector similarly commented that while non-discrimination rules were a positive step overall, they would not target the core issue of market power over long-term flexibility services.

4.17. Some submitters were more sceptical. For example, although NZ Steel said that it had initially favoured Option 2, it ultimately believed that none of the options would bring appreciable change and would only create more reporting and monitoring. NZ Steel also argued the LPF Options paper had not presented evidence that non-discrimination obligations would address current market issues, and they could exacerbate the affordability issue.

4.18. Other submitters opposed Option 2. The Mercury panel did not think the proposed obligations would prove effective or workable. The efficacy critiques focused on the practicalities of establishing an internal hedge portfolio. Nova did not agree with the non-discrimination obligations and argued the solution to managing the limited availability of hydro generation should focus on how it was offered into the spot market and its pricing.

Our response

4.19. The Authority considers Option 2 (non-discrimination obligations) continues to be a proportionate response but agrees with issues that submitters have raised about the internal hedge portfolio and many of the issues raised with implementation and escalations. We have amended the Option 2 proposals to take into account the feedback and details are presented in the following chapters. We invite feedback on the amended proposals, including on the extent to which these have addressed some of the concerns raised about Option 2.

Option 3 – Negotiate-arbitrate regulation

4.20. Negotiate-arbitrate regulation seeks to encourage parties to reach commercial agreement through negotiation, thereby limiting the need for direct regulatory intervention. This regulation could be achieved by:

- imposing an obligation on gentailers to provide access to hedge contracts on fair, reasonable and non-discriminatory (FRAND) terms
- requiring binding arbitration if commercial negotiations are unsuccessful.

4.21. Submitters were mostly opposed to Option 3 with some suggesting it was simply inappropriate or impractical, such as Octopus Energy, who thought Option 3 would not be workable, and Contact, who said Option 3 was not proportionate to the evidence.

4.22. Another concern expressed by submitters was the risk of additional costs, particularly in the form of delays. Business NZ feared Option 3 could become slow, legalistic and costly, while NZ Steel thought Option 3 would be difficult to implement and would reduce the pace of decisions. Neoen echoed other submitters' fear of delay and suggested the process would introduce complexity, while the IER thought Option 3 was ill-suited to hedge markets and would place the compliance burden on smaller players.

4.23. On the other side, Meridian supported its expert CSA's proposal for negotiate-arbitrate to be a 'safe harbour' exempting a participant from the non-discrimination regime. Lodestone Energy, although preferring Option 2, suggested Options 2 and 3 could be developed in parallel, and recommended the costs of each be assessed.

4.24. We acknowledge submitters' objections to Option 3 in terms of the risk of negotiation-arbitration being 'slow, legalistic and costly'. For the reasons set out in the LPF Options paper we continue to believe that negotiate-arbitrate is not well suited to being our primary level playing field intervention, but it could be suited as a possible targeted escalation for non-compliance in specific cases.

Option 4 – Corporate separation with arms-length requirements

4.25. Corporate separation would require a gentailer's retail and generation business units to be separately and independently managed, with each having their own business strategies and performance indicators. This would require a gentailer's generation business to deal with its retail business on an arms-length commercial basis, as though it were a third-party retailer.

4.26. Corporate separation would represent a significant shift in operating model and would likely require primary legislation. It also represents the most expensive option, requiring structural change to gentailers' businesses. This would result in the loss of the existing efficiencies associated with vertical integration (e.g. resources, systems and risk management).

Feedback

4.27. Option 4 drew mixed responses from submitters. Those opposed to Option 4 generally argued the scale of the change would create significant upheaval and uncertainty. For example, Genesis disagreed with Option 4 on the basis that it risked high costs and uncertain benefits. Nova similarly feared the proposal would create increased costs and would damage New Zealand's capital markets. Other submitters who did not support Option 4 included Contact, who thought it was disproportionate to the evidence, and the Business NZ Energy Council, who thought it would add additional costs and cause disruption to the market.

4.28. On the other side, Octopus Energy expressed support for corporate separation. They argued that this could be achieved quickly, at "modest cost" and was legally possible through a Code amendment. They said that the Authority's LPF Options paper had overstated the costs and understated the benefits of separation. The IER took a similar view, arguing that the LPF Options paper had failed to consider broader competition concerns.

4.29. Other submitters suggested corporate separation be retained in case regulatory measures did not produce the expected outcomes. For example, while Consumer NZ believed that a move to complete corporate separation could be unnecessarily disruptive, it suggested corporate separation be considered a backstop option if targeted measures did not achieve the desired results. NZ Steel similarly recommended Option 4 remain a stream of work but not form the current focus as more urgent initiatives are currently required.

Our response

4.30. We outlined our views on vertical integration in the previous chapter. We do not consider Option 4 to be useful, at this stage, for addressing market power issues in either flexible generation or the broader electricity market.

4.31. We agree with submitters who argue that it would have high costs, and uncertain benefits. We also agree that it would cause significant upheaval and uncertainty. In our view it is disproportionate to the scale of the problem that we have identified. We do not agree with Octopus' assertion that it could be achieved quickly. Based on the experience of the operational separation of Telecom, we can see that any separation is complex, time-consuming and disruptive for any organisation with an integrated business model. We also consider that an intervention of this kind would likely require primary legislation.

Investment incentives

4.32. There were also views expressed on the impacts of the LPF proposals on incentives to invest in generation in the future. The gentailers generally highlighted various risks that they saw from the LPF proposals that would decrease investment incentives. These views were based on slightly differing views on the implications of the LPF proposals.

- Genesis believed that the LPF proposals would undermine investment by increasing uncertainty. They also believe that it would undermine the case for maintaining existing flexible generation, not just future generation. It raises questions over the future of the third Rankine unit as it would run less frequently and require higher prices.
- NERA argued that the LPF proposals risk discouraging investment. In times of rising prices, gentailers would be required to sell hedge contracts at internal transfer prices (ITPs). The ITPs would be based on historic prices when prices were lower and so the hedge would be under-priced. Below market value of hedges would take away from the value of building flexible generation, hence reducing incentives to build it.
- NERA also argued that if complying with no-subsidy requirement means adopting a shorter-term hedging strategy, there will be more volatile retail prices. Generation will therefore be supported by more volatile retail income, which is a less reliable basis to support investment in infrastructure with a long pay-back period.
- Meridian said that if the proposed principles led to the sharing of benefits of vertical integration, there will be less incentive for independent retailers to invest in generation since they will have the benefit of owning generation without putting capital at risk. It could also affect incentives for gentailers, if extra capacity necessitates further hedge volume offers.
- Contact argued that all the LPF options have negative impacts on investment incentives. Barriers to investment in flexible generation apply equally to incumbents and newcomers. If the proposals lead to the Authority being the judge of "fair" prices, rather than the market, this increases credit risk. This would be mitigated if the Authority states it will not interfere in market pricing.

4.33. The arguments about the impact on investment incentives were theoretical. No gentailer gave us any specific evidence about current, likely or even hypothetical investment business cases that would be at risk from Option 2.

Our response

4.34. We have considered potential impacts on investment incentives. Submitters had diverse, and sometimes contradictory views on how Option 2 would be implemented. Some of the reasoning is based on the internal hedge portfolio which is no longer being required. Some of the reasoning about investment incentives was focused on the impacts of steps 2 and 3, which are no longer part of the proposal.

4.35. While we did not agree with all of the feedback about investment incentives, we acknowledge their importance particularly in the current environment where a material increase in generation is needed. We expect that our changes to proposed Option 2 will substantially reduce the risk to investment incentives. The removal of the previously proposed internal hedge portfolio, along with other changes, makes the proposed intervention more targeted and should have substantially less risk of compromising vertical integration efficiencies.

4.36. We are interested in feedback on the revised proposal's impact on investment incentives. Where stakeholders continue to assert a view that investment incentives would be harmed by our revised proposal, we would strongly encourage them to provide worked examples to demonstrate how that harm would occur.

Retail price effects

4.37. A number of submitters raised concerns that the LPF proposals risked increasing retail prices through various mechanisms:

- Sapere for Genesis said that portfolio flexibility keeps prices down and if this is removed, for example by forcing a gentailer to earmark fuel or flexible capacity to meet LPF, it would increase risk.
- Contact thought that more prescriptive ITPs could reduce competitive tensions and more public disclosure of sensitive commercial information (eg method to allocate scarce resources) increases risks of gaming.
- MEUG pointed to a discussion at the workshops about some gentailers running their retail operations at a loss. ERANZ saw this loss making as a part of price smoothing.
- NERA were concerned, based on the British experience, that increasing retailer entry could lead to unsustainable entry and market costs from retailer failures.
- Meridian predicted gradual retail price rises if gentailers can no longer fully capture the benefits from vertical integration (p29), and more volatile retail prices if retail offers had to be based on short term contracts (p30).
- CSA for Meridian estimated retail prices would have been 21-26% higher in December 2024 without price smoothing (p27-28).
- Cognitus (p3) submitted that its conceptual modelling indicated level playing field regulation would result in higher retail prices.

- Energy Resources Aotearoa were concerned that notions of “fairness” would shift prices away from least-cost solutions.
- Houston Kemp was concerned that Step 3 would incentivise corporate separation, with the resulting loss in efficiencies.

Our response

4.38. We have also considered the potential impacts on retail prices. Much of the same reasoning as we have applied to investment incentives applies to retail prices. Much of the reasoning about retail price increases was premised on the internal hedge portfolio, which no longer forms part of the proposal. Price issues will now be addressed through the retail price consistency assessment, outlined in more detail in Chapter 6. At least one gentailer has asserted that there is no margin squeeze, in which case there should be no issues. We have discussed the issue of price rises further in the context of the chapter on the retail price consistency assessment.

4.39. We do not believe the British example of retailer failures is relevant to New Zealand as market entrants have prudential requirements to ensure that there are no losses to customers or the broader market, in the event of retailer failure.

4.40. We are interested in feedback on the impact on retail prices of the revised proposal.

A number of submitters suggested alternatives to the LPF options

4.41. Many submitters took the opportunity to suggest alternatives to the LPF options. Some of these were in response to their views that we were focused on the wrong problem.

4.42. A number of these submissions focused on flexible generation. Genesis, Nova, MEUG, and Energy Resources Aotearoa called for support for flexible generation. Others were along similar lines with Sapere-Reeve calling for reductions in barriers to entry for low utilisation plant. The Mercury panel warned strongly against a strategic reserve mechanism. Energy Link suggested greater transparency on firming pricing and availability.

4.43. Some submitters suggested variations on the LPF proposals:

- Nova suggested corporate separation of Meridian, which could go as far as separating their residential and commercial customers.
- CSA recommended negotiate-arbitrate as a “safe harbour”.
- The Mercury panel suggested a technical industry group to keep improving the hedge market.

4.44. A few submitters (Consumer NZ, Entrust, Common Grace) suggested improvements to encourage consumer switching.

4.45. The Mercury panel suggested more work on demand side flexibility (also Clyde D’Souza, Energy Link), improvements to disclosure about the gas market (also Meridian), and expanded stress tests for those holding hedges.

4.46. A number of submitters suggested improving the working of the hedge market by increasing its transparency and liquidity. Some of these submissions had suggestions for improving the super-peak product. NERA, Meridian, Vector, the Mercury panel, IER, Vector and Mercury suggested market making for the super-peak product.

4.47. Nova argued that trading conduct rules may be a more appropriate avenue for dealing with pricing of super-peak hedges, rather than the LPF options. Carlson Consulting also proposed improved market rules.

4.48. Brian Leyland suggested a single buyer model.

4.49. Sinclair Electrical made specific recommendations about buyback rates for household solar energy, guaranteed meter upgrades and increased export volumes.

Our response

4.50. Some of the suggestions of alternatives to the LPF options, such as solar energy measures, demand side flexibility and consumer switching, are outside of the scope of this project. We have passed on feedback to relevant teams in the Authority, as there is already work underway on these issues. We have taken into account feedback on the super-peak product and are currently considering next steps following consultation on regulating the standardised super-peak hedge contract.

4.51. We agree that there are issues with the availability of, and incentives to build, flexible generation. Interventions that directly address this issue are outside of the scope of this level playing field work (which has a specific discrimination focus) and are part of the Government's response to its review of electricity market performance.

Questions

Q2. Do you have any new evidence that is relevant to the choice of level playing field interventions to address the identified competition issues?

5. Approach to applying non-discrimination obligations

5.1. This chapter explains our proposed approach to applying principles-based non-discrimination obligations (NDOs). It describes changes we have made after considering feedback on the LPF Options paper.

5.2. The NDOs are intended to give independent retailers and generators access to products (such as hedge contracts) on substantially the same terms as gentailers supply their internal retail divisions. The aim of the principles is to ensure the even-handed supply of risk management contracts, support the liquidity and competitive pricing of risk management contracts, and facilitate investment in the electricity industry.[32]

5.3. While focused on even-handedness, the revised NDOs are intended to work in concert with other initiatives to improve overall hedge market outcomes, including:

- strengthening trading of the super-peak standardised flexibility product[33]
- a review of market making in the electricity futures market to strengthen price discovery and promote healthy competition.

Summary of the proposed NDOs

5.4. We are proposing a Code amendment to introduce six non-discrimination principles, supported by record-keeping and disclosure obligations. Details of the draft Code amendment are included in Appendix A.

5.5. We have also prepared draft guidance on how we would expect gentailers to comply with the non-discrimination principles (see Appendix B). We intend to finalise this guidance, following consultation with stakeholders, before any Code change took effect. The guidance is intended to exist as a separate document, without being provided for in the Code itself, but could be turned into Code at a later point if necessary.

5.6. The proposed non-discrimination principles are listed below.

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[32] The proposed Code amendment in Appendix A includes a purpose section to help anchor what the Authority is aiming to achieve by introducing NDOs.

[33] Electricity Authority “Regulating the standardised super-peak hedge contract: issues and options – Consultation paper”, 19 August 2025, https://www.ea.govt.nz/documents/8199/Regulating_the_standardised_super-peak_hedge_contract.pdf .

Table 1: Non-discrimination principles

Principle	Proposed non-discrimination obligations
Principle 1: Non-discriminatory supply[34]	(1) A gentailer must not discriminate between buyers for the supply of risk management contracts without an objectively justifiable reason. (2) A gentailer must not discriminate against buyers in favour of its own internal business units for the supply of uncommitted capacity without an objectively justifiable reason. (3) A gentailer must not discriminate against buyers in favour of its own internal business units when pricing risk management contracts without an objectively justifiable reason. (4) For the avoidance of doubt, subclause (3) requires pricing of risk management contracts in such a way as to ensure that any buyer that supplies electricity to end users at retail, that is as efficient with regard to operating costs as the gentailer's own retail internal business unit, and adopts a reasonable risk management approach, is not prevented from operating profitably.
Principle 2: Obligation to trade in good faith	A gentailer must engage with buyers in good faith and in a timely and constructive manner in relation to the supply of risk management contracts.
Principle 3: Objective credit assessments	A gentailer's credit terms and collateral arrangements relating to the supply of risk management contracts to buyers must reflect a reasonable, consistent and transparent assessment of the risk of trading with a buyer.
Principle 4: Equal access to commercial information	A gentailer must ensure that any commercial information relating to risk management contracts made available to its internal business units that compete with buyers is also made available to buyers at the same time.
Principle 5: Protection of confidential information	A gentailer must protect buyer confidential information and establish robust processes to prevent disclosure of buyer confidential information to, and use of buyer confidential information by, any of the gentailer's internal business units that may compete with the buyer.
Principle 6: Record-keeping	A gentailer must establish, maintain and keep records that demonstrate its compliance with these non-discrimination principles.

[34] For the purposes of the NDOs, "objectively justifiable" is intended to require gentailers to apply an evidence-based approach that is reasonable, consistent and transparent. In the LPF Options paper, we referred to "*cost-based*, objectively justifiable" reasons. We have removed "cost-based" from the revised wording of Principle 1, because cost may not always be a relevant factor when assessing whether discriminatory treatment between parties is objectively justified.

5.7. Key changes from the non-discrimination principles proposed in the LPF Options paper are:

- We have removed the requirement for gentailers to construct economically meaningful internal hedge portfolios.
- We have instead added a requirement for gentailers to undertake regular retail price consistency assessments (RPCAs), which more directly test whether gentailers are discriminating in the pricing of risk management contracts in a way that favours their own retail business. RPCAs are to be undertaken to satisfy subclause (3) of Principle 1.
- A new principle has been added requiring gentailers to trade in good faith, including by engaging with buyers in a timely and constructive manner.

5.8. A core part of the design of the principles-based regime is to require gentailers to put robust processes in place to demonstrate their compliance. This includes:

- director certification that the gentailers have complied with the non-discrimination principles
- requirements to self-report any breaches of the principles
- regular reporting to the Authority and the public – including an interim report 6 months after the NDOs come into force, ongoing annual reporting demonstrating compliance with the principles, and 6-monthly RPCAs.

5.9. These changes seek to simplify the proposed NDOs, removing a key area of contention and potential ambiguity (internal hedge portfolios), without compromising on their core goal – addressing the risk of discrimination through access or pricing. In our view this revised proposal will be able to be implemented faster and will be more easily enforced.

Non-discriminatory pricing of hedges

Previous proposal

5.10. The LPF Options paper proposed that each gentailer would be required to establish an economically meaningful portfolio of prices for internal hedges. These internal hedges would have provided a benchmark against which offers to buyers could have been assessed, to help ensure non-discriminatory pricing.

Feedback

5.11. Some submitters (e.g., Vector and the Mercury panel) highlighted the challenges of constructing an internal hedge portfolio. They considered that without actual market transactions:

- pricing of internal hedges would be subjective and open to manipulation
- it would be difficult for an internal hedge portfolio to be "economically meaningful".

5.12. Mercury submitted that the proposed approach risks the Authority having to substitute its own judgement for that of the market, as well as adding transaction costs to the system which will flow onto consumers. Mercury considered that considerable rule design would be required.

5.13. Meridian submitted that it is not practical for a gentailer to build an internal hedge portfolio using market traded hedges, without changing the implicit internal contract itself, which is based on a complicated set of factors. Meridian suggested that:

- the requirement for internal hedge prices to be "based on observable market rates" be better defined
- gentailers should be able to grandparent in historic prices as part of their internal hedge portfolios.

5.14. Octopus submitted that a set of transition rules would be needed for gentailers to establish their initial hedge portfolios, ensure risk management access for third parties and prevent gaming. Octopus also considered that the Authority would need to oversee implementation and rebalancing of risk management contract prices to avoid a price shock and extraction of monopoly rents.

5.15. Link Economics (for IER) submitted that if NDOs are to be introduced, a price squeeze test requirement should be included (rather than simply a prohibition of cross-subsidies). It noted that:[35]

> Regulators who are concerned about discriminatory practices by firms with market power and margin squeezes typically apply either imputation tests or replicability tests. These tests have the effect of prohibiting cross-subsidies, while also assisting in both assessing whether the principle of non-discrimination in pricing is being adhered to and helping to avoid a substantial lessening of competition.

5.16. The Mercury panel (Houston Kemp) also commented that a key benefit of vertical integration is the natural risk management function of balancing generation against a retailers' expected load. This avoids the transaction costs of entering into contracts that would achieve a similar effect, as well as the risks associated with the availability, pricing and security of such contracts. In their view, a portfolio of implicit internal hedges will not reflect these integration efficiencies.

Our response

5.17. We propose not proceeding with the requirement for gentailers to develop economically meaningful internal hedge portfolios. We have taken on board concerns raised by some submitters regarding the feasibility of this approach, and the likelihood of achieving the objectives of the NDOs.

5.18. We were particularly concerned about the time it would likely take for gentailers to develop and implement internal hedge portfolios that would fit the purpose of the NDOs. While an internal hedge portfolio remains a useful option conceptually, we are no longer convinced that it is the best option for the current circumstances, where we are wanting to increase participants' confidence in the hedge market as soon as possible.

5.19. Instead, we are now proposing that the gentailers be required to demonstrate an economically justifiable link between the expected cost of supply and their retail

35 Link Economics, "Electricity retailing – adjusting the tilt of the playing field", May 2025, https://www.ea.govt.nz/documents/7355/Independent_Electricity_Retailers_aznaQGd.pdf.

prices by undertaking regular RPCAs. RPCAs are intended to assess whether a gentailer's pricing of risk management contracts allows an as efficient buyer to profitably operate in the retail electricity market (ie, whether a margin squeeze is occurring).

5.20. The RPCA will be used to monitor whether gentailers' hedge pricing is favouring their internal retail businesses over other buyers – in other words, whether they are complying with subclause (3) of Principle 1. This is intended to give other market participants confidence that the gentailers are not either cross subsidising their retail arm or inappropriately suppressing retail prices to undermine their downstream competitors.[36]

5.21. Removing the need to develop an internal hedge portfolio avoids potentially protracted hypothetical debates and a requirement for a level of granularity greater than necessary for the proposed intervention. Focusing on RPCA more directly is intended to give confidence to retail market participants that gentailers are not taking advantage of their market position and directly addresses that margin squeeze complaint that has been made by independent retailers for some time.

5.22. Further detail on the proposed approach to RPCAs is included in Chapter 6. For example:

- We are proposing to develop and publish detailed guidance for RPCAs, prior to the first assessment, to ensure consistency and comparability in approach across gentailers. We intend to develop this guidance in consultation with market participants.
- The Authority intends to regularly process information received through RPCAs, analyse results to identify any patterns that may raise concerns, and publish summaries. The information will also inform any potential improvements to the guidance.

Non-discriminatory access to hedges

Previous proposal

5.23. The LPF Options paper proposed that gentailers should be unable to allocate uncontracted hedge volumes to their own retail function in preference to third parties. Effectively at each point in time when selling hedges, gentailers' generation functions would need to ensure that they were being even-handed in their allocation between all their customers (internal and external).

5.24. Gentailers' internal hedge portfolios would have informed the availability of uncontracted[37] volumes available for buyers.

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[36] We consider that the RPCA sufficiently addresses concerns about cross-subsidisation, so are not proposing separate reporting of cross-subsidies (or a new principle prohibiting cross-subsidisation, as some submitters suggested).

[37] "Uncontracted" was intended to mean hedge volumes that a gentailer does not have binding contractual arrangements for (including both internal and external arrangements).

Feedback

5.25. Submitters were divided on the approach for providing access to uncontracted hedge volumes.

5.26. Contact submitted that it did not prefer its retail arm ahead of other buyers and urged care to ensure the proposed regime does not distort price signals or increase retail prices. Meridian argued any requirements should include guidance on how "uncontracted hedge volumes" should be calculated, while Nova suggested a gentailer's retail unit could retain a first right of refusal for any volume required to be made available for third party offers. NZ Steel suggested that while preventing gentailers from favouring their own internal retail arms appeared attractive, it could lead to unintended consequences.

5.27. In contrast, the EEA advocated for a principles-based framework to prevent gentailers from favouring their own retail arms. Lodestone Energy suggested gentailers be required to clearly identify uncontracted volumes, while Octopus Energy recommended a package of measures including internal trading protocols, accounting separation and enforcement action. The IER argued the complexity and difficulty of non-discrimination rules was evidence that corporate separation and arm's length rules should be the preferred option.

5.28. NZIER (for MEUG) submitted that defining and measuring future supply of dispatchable generation, and probability of availability, is key to making non-discrimination workable and demonstrating effectiveness.

Our response

5.29. We have amended our proposed approach to reflect removal of gentailer internal hedge portfolios.

5.30. Our revised proposal is that gentailers should provide market participants with access to *uncommitted capacity*[38] on the same terms as the gentailer's retail arms.[39] This would require gentailers to allocate uncommitted capacity on a non-discriminatory basis and would prevent a gentailer from prioritising supply of that capacity to its internal business units over third party purchasers.

5.31. "Uncommitted capacity" is intended to reflect the forecast availability of generation controlled by a gentailer in the relevant period, taking account of expected fuel

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[38] The change in terminology from "uncontracted hedge volumes" in the LPF Options paper to "uncommitted capacity" in this paper reflects removal of the requirement for gentailers to develop internal hedge portfolios. "Uncontracted hedge volumes" was intended to mean hedge volumes that a gentailer does not have binding contractual arrangements for (including both internal and external arrangements). Binding contractual arrangements for gentailers' internal hedge volumes will not exist under our revised proposal, so we have referred to "uncommitted capacity" instead.

[39] Uncommitted capacity means a gentailer's reasonable expectation of its ability to offer risk management contracts in future periods, calculated as a gentailer's expected gross forecast ability to offer risk management contracts, less:

- the amount of generation, that could otherwise be used to back risk management contracts, the gentailer reasonably expects to use to supply electricity to its end customers; and
- a gentailer's wholesale commitments, comprised of gentailer market making commitments (regulated or voluntary) and existing risk management contracts entered into with buyers.

availability and outages, and is consistent with submitter feedback that gentailer uncontracted volumes should be clearly identified. It is to be calculated as a gentailer's gross forecast capacity to offer risk management contracts less:

- the volume of electricity they reasonably expect to supply to their end customers (allowing for organic growth only)
- their wholesale commitments, comprised of gentailer market making commitments (regulated or voluntary) and existing risk management contracts entered into with buyers.

5.32. Our proposal would require gentailers to regularly disclose their capacity to offer risk management contracts, along with any responses to buyer requests for contracts that do not conform to the buyer's specifications.[40]

5.33. For the avoidance of doubt, the proposed approach to providing access to hedges is not intended to:

- require a gentailer to break existing contracts with its end customers
- require a gentailer to stop acquiring, or to actively seek to divest itself of, end customers.

5.34. However, the proposal does prevent a gentailer from allocating future generation capacity to planned growth in its own retail internal business unit without testing market interest in that capacity.

5.35. By way of example, in assessing a gentailer's level of uncommitted capacity we expect that:

- capacity to support organic customer growth (consistent with historic trends or reflecting whole of market changes)[41] would prima facie be considered committed
- capacity to support an acquisition of another retailer's customer book would prima facie be considered uncommitted (ie, contestable between buyers and a gentailer's internal business units)
- if a gentailer is actively acquiring, or seeking to acquire, net new retail customers, there will be a (rebuttable) presumption that it has uncommitted capacity available.

Who should non-discrimination requirements apply to?

Previous proposal

5.36. The LPF Options paper proposed that the non-discrimination obligations should apply to the four large gentailers that control the vast majority of New Zealand's flexible generation: Contact Energy Ltd, Genesis Energy Ltd, Meridian Energy Ltd and Mercury NZ Ltd.

40 As noted in paragraph 7.11, reasons for non-conforming offers are likely to be collected through the proposed cl 2.16 notice (rather than directly through the NDOs).

41 For example, growth driven by consumers purchasing an electric vehicle for the first time and charging it at home.

5.37. We sought feedback on whether smaller gentailers should be subject to the proposed level playing field measures.

Feedback

5.38. There were differing views on the application of LPF requirements to smaller gentailers:

- Octopus, SEANZ, Nova, Helios and Lodestone agreed the measures should be targeted at the big four gentailers.
- Geoff Henderson suggested smaller gentailers should be exempt from the non-discrimination obligations if they do not own any hydro.
- The EEA submitted that the regulatory approach should be proportionate with appropriate thresholds or exemptions for smaller gentailers.
- Common Grace, Meridian and Consumer NZ believed that smaller gentailers should be regulated in the same way as the four large gentailers.
- Contact submitted that it would be inconsistent to exclude Nova, given it has a similar amount of access to thermal peaking as Contact.

Our response

5.39. Our view remains that the NDOs should apply to the large four gentailers only.

5.40. Our concerns are focused on the combination of vertical integration and market power, which the gentailers maintain through their control of the flexible generation base. The four large gentailers are the main suppliers in both the retail and wholesale electricity markets. They have:

- combined retail market shares of around 86%
- generated around 85% of New Zealand's electricity since 2010.[42]

5.41. Although Nova is a gentailer, which has flexibility with its gas-fired peakers, it does not raise the same market power concerns as the four large gentailers. This is because:

- Nova provides only a small proportion of New Zealand's total flexible generation capacity
- a potential competitor can develop gas peakers relatively easily, unlike large hydro dams such as those operated by the big four gentailers[43]
- gas peakers are constrained by the availability of gas.

[42] Electricity Authority "Level playing field measures: Options Paper", 27 February 2025, Figure 3 https://www.ea.govt.nz/documents/6605/Level_playing_field_measures_options_paper.pdf.

[43] However, gas peakers face other challenges such as carbon pricing and negative perceptions regarding carbon emissions.

5.42. We also note that Contact has now acquired Manawa's generation assets, which has added to its flexibility.[44]

Which products should non-discrimination obligations apply to?

Previous proposal

5.43. The LPF Options paper proposed the non-discrimination obligations should apply to all hedge contracts, including super-peak, peak and baseload. We noted that:

- a narrow non-discrimination regime, focused on one category of hedge contracts, could leave opportunities for discriminatory behaviour for the remaining hedge products
- it is not clear to us that there would be significant downside to extending any non-discrimination requirements to all hedge products.

Feedback

5.44. Some submitters suggested that the NDOs should be focused on specific categories of hedge contracts. For example, Meridian considered the Authority should focus on ensuring a competitive and liquid market for super-peak products. Nova agreed, arguing that this was the only flexibility identified as a source of market power once thermal generators are retired. Contact submitted the obligations should not apply to baseload hedges, which are highly liquid on the ASX and subject to market making obligations.

5.45. Other submitters argued that NDOs should apply more broadly. Consumer NZ considered that non-discrimination obligations should apply to all hedge products rather than only super-peak hedges, while Octopus Energy argued that restricting obligations to super-peak products would enable continued discrimination through other instruments. NZ Steel similarly saw no value in restricting the application of non-discrimination obligations and argued that baseload products should be included.

5.46. Submitters who supported the wider application of NDOs included the EEA, Geoff Henderson, Helios, IER and SEANZ. Energy Link suggested the measures apply to baseload and super-peak products initially.

Our response

5.47. Our proposal is to apply non-discrimination obligations to the broad range of hedge contracts offered by gentailers. In our view, applying these obligations narrowly to only selected products would risk distortions through the creation of undesirable incentives and ultimately undermine the integrity of the non-discrimination regime.

5.48. A narrow non-discrimination regime, focused on one category of hedge contracts, could leave opportunities for discriminatory behaviour for the remaining hedge products. For example, if non-discrimination obligations were applied to super-peak hedge contracts only, gentailers would retain the ability — and perhaps have greater

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[44] Contact Energy "Contact Buys Manawa Energy", accessed 31 July 2025, https://contact.co.nz/support/notice/manawa.

incentives — to discriminate when providing baseload and peak hedge contracts in future.[45]

5.49. In addition, we expect that the RPCA will depend on the portfolio of risk management contracts offered by gentailers to inform the expected cost of electricity supply. Our current view is that the RPCA could not be meaningfully informed by super-peak hedges alone. Rather, a mix of baseload, peak and super-peak hedges will be relevant. Depending on the retail pricing approach of the gentailer, a mix of hedge durations may also be relevant, including longer term hedges that enable smoothing of retail prices over a number of years.

5.50. At this stage we anticipate that the compliance costs of including all hedge contracts in the non-discrimination obligations would not be materially greater than if the NDOs were focused on a single category or class of risk management contracts.

5.51. More generally we are satisfied that applying the NDOs to a broad range of hedges is a proportionate response to the risk that we have identified. By contrast, waiting until there was clear evidence of an access or pricing problem for any hedges other than super-peak (with evidence almost certainly lagging the problem) would seem to us to work directly against the market confidence that we are trying to improve through these LPF measures.

Who should be included as "buyers"?

Previous proposal

5.52. The parties able to access risk management contracts through the NDOs were defined as "buyers" in the LPF Options paper. The LPF Options paper proposed a broad definition of "buyer" including a person who any of the following apply to:

- is specified as the buyer in risk management contracts with a gentailer
- has otherwise obtained, or is obtaining, a risk management contract from a gentailer
- has indicated to a gentailer a desire to obtain risk management contracts from the gentailer.

Feedback

5.53. Meridian suggested only physical market participants should have non-discriminatory access to hedges. Meridian's underlying concern is arbitrage.

5.54. Meridian argued that the definition of "buyer" should be restricted to New Zealand wholesale market participants. Meridian considered that extending the same rights to non-participants would require gentailers to sell volumes to offshore speculators who would in turn sell back to New Zealand wholesale participants at a premium,

[45] While baseload hedge contracts are subject to market making obligations via the ASX, a number of baseload contracts are still traded OTC, so the existence of ASX market making obligations is not a complete answer to this concern.

ultimately costing domestic market participants and consumers. They considered these risks would be significant if arbitrage opportunities arose due to the proposal.

5.55. By contrast, MEUG supported a broader approach which captures customers who buy directly from wholesale and intermediaries, and recommended this be made explicit in the definition of "buyer." Octopus Energy suggested that definition of "buyer" incorporate third party sellers of energy rather than only risk management products.

Our response

5.56. We consider that non-discriminatory access should apply to all parties that facilitate competition. This includes financial intermediaries, who can contribute to increased competition in both supply and demand for hedge products, thereby driving down costs for independent retailers and ultimately consumers.

5.57. We are proposing a broad definition of "buyer" that includes financial intermediaries. Our proposal is to use the existing definition of "buyer" in the Code, but amend this to clarify that for the purposes of the NDOs a buyer:

- includes a person that has indicated to a gentailer a desire to obtain risk management contracts from a gentailer
- does not include a gentailer's own internal business units.

5.58. We are proposing to capture financial intermediaries because:

- We do not agree that "arbitrage" is per se bad. Rather, arbitrage can be a useful and necessary part of the process of price discovery. Without financial intermediaries, there is a risk that price discovery will be less effective, especially in a small market like New Zealand. In addition, we have not been presented with any actual evidence of material downside of allowing financial intermediaries to trade in New Zealand electricity hedges, eg, on the ASX where access to a minimum volume of market made baseload hedges is part of the trading arrangements.
- Financial intermediaries can play an important role in warehousing and aggregating risk on behalf of smaller physical market participants. Financial intermediaries repackage discrete contracts into a form suitable for other purposes and bridging limitations in counterparty credit availability. The hedging instruments they provide can allow generators, utilities and large-scale consumers to manage price risks more effectively.
- Financial intermediaries promote liquidity by buying and selling contracts (e.g., futures, forwards, or options), and correcting market inefficiencies/imbalances through the price discovery processes.

Large commercial and industrial users

5.59. We recognise the importance of access to hedges at competitive prices to large commercial and industrial users. Large commercial and industrial users were accordingly captured within the definition of 'buyer' in the LPF proposal set out in the LPF Options paper.

5.60. Our revised proposal in this paper has more specific focus on competition, particularly ensuring that retailers are being treated even-handedly (a relativity test) compared with the gentailers' retail functions. This is reflected in the removal of the requirement for gentailers to specify an internal hedge portfolio, and the introduction of the RPCA.

5.61. These proposals are part of a wider reform package in relation to the hedge market, with other aspects of that package (e.g., the market making review) likely to do more heavy lifting in pursuit of improved hedge liquidity and (objective) assurance of competitive hedge pricing.

5.62. Noting this change in emphasis, it is now less clear to us that continuing to include large commercial and industrial users within the definition of 'buyer' is useful. While subclause (1) of Principle 1, and Principle 2, could still logically apply to large users, the increased even-handedness focus of the NDOs seems less likely to address those users' fundamental concern about liquidity and competitive pricing.

5.63. However, we note that MEUG, as the representative body for large users, in its May submission "support[ed] the proposed intervention (Option 2) that will give other market participants (including a number of our members) access to hedge products on substantially the same terms as the gentailers supply themselves internally".

5.64. At this point large users remain within the revised definition of 'buyer'. We would welcome feedback from submitters on the costs and benefits of retaining them within that definition, as opposed to narrowing its scope.

5.65. If large users remain within the definition of 'buyer', a further technical question arises about whether there should be a carve out from the NDOs for any contract that is also caught by the materially large contract (MLC) provisions in the Code.[46]

5.66. The MLC provisions are targeted at a very specific problem – inefficient price discrimination in relation to very large electricity supply contracts.[47] The Authority estimated in 2023 (and continues to believe) that the MLC regime would apply to only a small number of contracts.

5.67. Under the MLC Code provisions an MLC is prohibited unless it passes one of two tests:

- an economic test of whether the value of the MLC to the generator is greater than the value to the generator of its best alternative (net value test)
- a legal test of whether the MLC allows electricity to be on-sold by the purchaser to a third party, on no worse terms than if the purchaser had consumed the relevant quantity itself (on-selling test).

5.68. The MLC regime was put in place to recognise that there are a small number of instances where an electricity supply contract could effectively move the market and put in place efficient protection in those scenarios.

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46 Subpart 7 of part 13 of the Code.

47 Defined as "contracts (or combinations of contracts) not entered into through a derivatives exchange and includes terms under which the buyer itself will consume a quantity of electricity of net 150MW or more".

5.69. Noting that MLCs have their own regulatory regime and that, given they are likely to be very small in number and negotiated between parties that all have material resources and bargaining power, our current view is that the NDOs are unlikely to have any useful impact[48] in relation to a contract that is also caught by the MLC provisions of the Code.

5.70. We invite feedback on whether risk management contracts that are also MLCs under the MLC regime in the Code should be excluded from the proposed NDOs.

Consideration of volume when assessing non-discrimination

Previous proposal

5.71. The LPF Options paper proposed that volume should not be considered when applying Principle 1 (non-discriminatory supply) and Principle 3 (objective credit assessments). The intention was to effectively remove the ability for gentailers to offer volume discounts, noting that the gentailers would be by far the largest buyers of risk management contracts, so may receive more favourable pricing if discounts were allowed.

5.72. We sought feedback on:

- how far the allowance in the principles for different treatment should extend where there was a "cost-based objectively justifiable reason"
- whether stakeholders agreed that this allowance should not be extended to volume.

Feedback

5.73. Meridian argued that gentailers should be able to consider volume in credit and collateral arrangements with buyers. Contact agreed, submitting that that the consideration of volume should be permitted, and that preventing this would deny consumers benefits of scale efficiencies.

5.74. Other submitters offered a different view. For example, the EEA supported an allowance to reflect genuine operation and financial differences, but did not think this should extend to volume, as this would risk creating loopholes for anti-competitive bundling. The IER submitted that there should be no allowance for volume-based differences in treatment, even on a cost basis, as this would undermine the regime.

Our response

5.75. We agree that gentailers should be able to consider volume when assessing counterparty risk as part of a credit assessment. As noted by Meridian, credit risks

48 In terms of the hedge liquidity, competitive pricing and even-handedness are outcomes that the Authority is seeking.

are related to volume and sellers should be able to ensure they are not exposed to undue credit risks in respect of higher volumes.[49]

5.76. We have amended the guidance on Principle 1 to clarify that volume considerations can lead to different commercial terms for buyers, where those terms are based on objectively justifiable reasons.[50] This approach allows consumers to benefit from scale efficiencies, as suggested by Contact.

5.77. However, we expect the magnitude of any pricing variations based on scale efficiencies to be small. The NDOs apply to trading of financial contracts rather than a physical product, so for example, our current expectation is that there would not be sufficient economies of scale to justify substantial volume discounts.

Good faith obligation and relationship with OTC Code of Conduct

Previous proposal

5.78. The LPF Options paper did not include a requirement for gentailers to act in good faith. It also did not specifically address the relationship between the proposed non-discrimination obligations and the existing Voluntary Code of Conduct for participants in New Zealand's Over the Counter Electricity Market (OTC Code of Conduct), which includes a good faith obligation.[51]

5.79. Appendix B of the LPF Options paper noted that, at that stage, the Authority was not consulting on how non-discrimination obligations might interact with existing processes such as the OTC Code of Conduct.

Feedback

5.80. Octopus proposed a new principle requiring gentailers to trade in good faith. In particular, Octopus suggested that gentailers should be required to engage with counterparties in a timely and constructive manner.

5.81. In addition, some submissions suggested reforms to the OTC code of conduct. In particular, the Mercury panel suggested amendments to clarify the circumstances where a party would not be required to provide a quote or enter into a trade. The Mercury panel additionally recommended greater disclosure requirements as the first regulatory option to improve confidence in the OTC market.

5.82. Mercury proposed converting the voluntary OTC Code of Conduct into a mandatory code, to be accompanied by robust monitoring and enforcement provisions.

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[49] For example, Meridian noted that 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.

[50] As noted in paragraph 4 of the guidance (see Appendix B), "objectively justifiable" is intended to require gentailers to apply an evidence-based approach that is reasonable, consistent and transparent.

[51] See paragraphs 21.6 and 24 of the OTC Code of Conduct.

Our response

5.83. We have proposed a new good faith principle, as suggested by Octopus. We agree that an overarching obligation to engage in a timely and constructive manner is a useful addition to the NDOs. We have also provided guidance regarding matters we expect to be considered in determining whether a gentailer has acted in good faith, including:[52]

- whether the gentailer has acted honestly
- whether the gentailer has been responsive and communicative
- whether the gentailer has not acted arbitrarily, capriciously, unfairly, or unreasonably
- whether the gentailer has not acted in a way that constitutes retaliation against a buyer for past complaints and disputes
- whether the gentailer has observed confidentiality requirements relating to buyer confidential information (including in accordance with Principle 5)
- whether a buyer's requests for risk management contracts are reasonable (for example, by providing reasonable timelines, by providing reasonably required information and being issued where there is a genuine intention to transact).

5.84. Our view is that mandatory non-discrimination principles can operate alongside the existing OTC Code of Conduct, given that the voluntary OTC Code of Conduct makes it clear that it is not binding, does not have the force of law, and "in no way supersedes or alters the legal obligations of parties in the OTC market", including compliance with the Act and the Code (among other legislation). By contrast, the proposed non-discrimination principles would be enacted as provisions in the Code. It follows that the non-discrimination principles (as enacted within the Code) would take precedence over the obligations in the OTC Code of Conduct.

5.85. We have incorporated some elements of the OTC Code of Conduct into the draft guidance that sits alongside the non-discrimination principles.[53] In particular, parts of the OTC Code of Conduct are helpful in explaining expected behaviours to comply with the new "good faith" principle.

5.86. Our view is that mandating the voluntary OTC Code of Conduct is not a suitable alternative to the proposed non-discrimination obligations. While the proposed non-discrimination regime is focused on the conduct of gentailers, the OTC Code of Conduct applies to all participants involved in trading risk management products in the OTC market. While participants commit to the principle of treating all OTC market participants consistently and without prejudice under the OTC Code of Conduct, it does not explicitly prohibit gentailers from discriminating against buyers in favour of their own business units in the same way as the proposed non-discrimination

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[52] Even though the concept of "good faith" is relatively well known (particularly in the employment context), this guidance is intended to better describe what good faith involves in the particular context of the non-discrimination obligations.

[53] See paragraphs B.13 to B.17 of the draft guidance in Appendix B.

obligations. The OTC Code of Conduct is not currently supported by clear record-keeping and disclosure requirements, as contained in the proposed non-discrimination regime.

5.87. To be clear, the Authority has a positive view of the OTC Code of Conduct and respects the participant effort that went into developing it. Our proposal to not adopt the OTC Code of Conduct as a core part of the non-discrimination regime is based more on context, specifically that the OTC Code of Conduct is a different mechanism that was looking to resolve a different (albeit overlapping) issue.

5.88. We are, however, interested in feedback on whether the OTC Electricity Market Working Group should be reconvened to assess whether any amendments might be made to the voluntary OTC Code of Conduct to reflect the proposed non-discrimination regime.

Should new generation/flexibility investments be ring-fenced?

Previous proposal

5.89. The proposed approach to implementing NDOs in the LPF Options Paper did not distinguish between new investments in flexible generation and existing assets.

Feedback

5.90. Meridian submitted that new generation/flexibility investments should be excluded from the non-discrimination regime, to avoid chilling investment incentives.

5.91. Meridian suggested that:

- To make the proposal workable, the Authority would need to specify how the 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
- The Authority should consider explicitly excluding new investment after a specified date to avoid weakening investment incentives.

Our response

5.92. We are not proposing to carve out new generation/flexibility investments from the NDOs. Under the proposed NDOs gentailers should continue to receive market rates for hedges they supply to buyers or internal customers unless they are engaging in a retail margin squeeze. It is therefore not clear to us how this could have any material chilling effect on investment. If gentailers disagree with this logic, we would expect them to provide us with worked examples of plausible investments in their submissions setting out exactly how this chilling effect would occur.

5.93. In addition, there would likely be challenges and complexities in excluding new flexibility investments from the NDOs in practice. For example, it is unclear how long any carve outs should apply for.

Other non-discrimination principles

Previous proposal

5.94. Principles 3 to 6 of the LPF Options paper included requirements regarding:

- Objective credit assessments (Principle 3)
- Equal access to commercial information (Principle 4)
- Protection of confidential information (Principle 5)
- Record keeping (Principle 6).

Feedback

5.95. Many submissions commented on the proposed approach to monitoring and enforcement of the NDOs, including the record keeping and disclosure requirements related to Principle 6. This feedback is discussed more detail in Chapter 7 below.

5.96. There was limited specific feedback on Principles 3-5 (as listed in paragraph 5.94). However, Octopus suggested some revisions to these principles intended to improve clarity.

5.97. Octopus also suggested a new principle requiring that gentailers maintain non-discriminatory policies describing internal operational practices to ensure trading of risk management contracts is consistent with the NDOs.

Our response

5.98. Our revised approach to record keeping and disclosure requirements is described in Chapter 6 below. Although Principle 6 remains largely unchanged from the LPF Options paper, we have refined the detailed record-keeping and disclosure requirements proposed to be included in the Code. These amendments include a new requirement for gentailers to maintain non-discriminatory policies (as suggested by Octopus) and to prepare implementation plans detailing their approach to complying with the NDOs.

5.99. We have also made some wording amendments to Principles 3, 4 and 5 to improve clarity.[54] The substance of these principles remains consistent with the LPF Options paper.

5.100. We consider that the proposed requirements regarding credit terms, sharing of commercial information and protection of buyer confidentiality are important aspects of the non-discrimination regime. However, we have not discussed these principles in detail in this paper given the limited feedback we received on them.

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54 As noted in paragraphs 5.75 to 5.77 above, we have also updated the guidance for Principle 3 to clarify that gentailers can consider volume when assessing counterparty risk as part of a credit assessment.

Questions

Q3. Do you have any feedback on our proposed approach to implementing principles-based non-discrimination requirements, as set out in Chapter 5? If you disagree with elements, how would you improve them?

Q4. Do you agree that substituting an RPCA test for a requirement to develop an internal hedge portfolio will be more effective at ensuring non-discriminatory pricing than the proposals in the LPF Options paper? Why or why not?

Q5. Is our proposal around “uncommitted capacity” workable? What suggestions do you have for improving it?

Q6. Do you have any further evidence, particularly relating to costs or incentives, about the impact of applying NDOs to all risk management contracts rather than just super-peak hedges?

Q7. Should large users be included as buyers under the NDOs? If so, is a carve out needed for risk management contracts approved under the MLC regime?

Q8. Should the OTC Electricity Market Working Group be reconvened to assess whether any amendments might be made to the voluntary OTC Code of Conduct to reflect the proposed non-discrimination regime?

Q9. Should investment in new flexible generation assets be carved out from the proposed NDOs? Why or why not? If you think new investment should be ringfenced, please provide details of how you suggest any carve outs be implemented.

Q10. What impact do you think the revised NDOs will have on retail prices and/or incentives to invest in generation? How does this compare to the impacts you posited in response to the LPF Options paper? Can you share any evidence that supports your view?

6. Retail price consistency assessment

6.1. The purpose of this chapter is to set out how the Authority expects the RPCA to operate, and how it intends to develop the details of the RPCA.

Proposal to require regular retail price consistency assessments

6.2. The Authority proposes to require large gentailers to regularly undertake and disclose a RPCA.

6.3. Passing this assessment would assist to demonstrate that a gentailer is acting in accordance with Principle 1, subclause (3) (ie, the gentailer is not discriminating against third parties, in favour of its own retail function, on price).

6.4. The Authority proposes that gentailers would submit their initial RPCAs to the Authority on 1 July 2026, ie, the proposed commencement date of the NDOs.

6.5. The Authority intends to create RPCA guidance to ensure the assessment is applied in a consistent and comparable manner. We intend to seek significant technical input from market participants when developing this guidance.

6.6. To ensure the RPCA guidance is complete in time to provide practical assistance, so gentailers can submit a robust initial RPCA, the Authority intends to commence RPCA guidance development ahead of any decisions on the proposals.[55]

Purpose of the assessment

6.7. The Authority is proposing to require that a gentailer must not discriminate against buyers in favour of its own retail business when pricing risk management contracts.

6.8. To satisfy this requirement, a large gentailer would have to price risk management contracts so that another retailer that is as (or more) efficient with regard to operating costs as its own retail business, and adopts a reasonable risk management approach, is not prevented from operating profitably in the electricity retail market.

6.9. To give effect to this requirement it is proposed that each large gentailer would have to regularly demonstrate an economically justifiable link between the expected cost of electricity supply and its retail pricing.

6.10. The assessment would check whether a large gentailer is discriminating through over-pricing of risk management contracts or by setting its retail prices below cost – either of which could amount to an anti-competitive squeezing of competing retailers' margins.

Reason for moving to this proposed approach

6.11. Chapter 5 (paragraphs 5.17-5.22) sets out the Authority's considerations in proposing this approach to achieve the objectives of the NDOs.

[55] The Authority acknowledges that by starting preparatory work early it risks that such work may not be needed if the Authority decides not to go ahead with all or parts of the proposal after consultation. However, this means that if the proposal is adopted then the guidance can be available for gentailers by the time any Code amendment comes into force.

6.12. The LPF Options paper proposed requiring gentailers to develop economically meaningful internal hedge portfolios for assessing whether their pricing of hedges complied with the NDOs. Several submissions highlighted the conceptual and practical challenges of constructing such portfolios.

6.13. The proposed approach avoids the construction and explicit pricing of implicit internal hedge portfolios, or reliance on ITPs. A post implementation review had found there was consensus that the current ITPs were not useful for understanding competition in the retail electricity market (see Chapter 11).[56]

6.14. Instead, the proposed RPCA would rely on market information and other information that we understand gentailers already hold. For example, they will have their own views of the expected cost of supply, and these can also be observed from hedge market transactions over a reasonable timeframe leading up to the point at which they set retail prices, reflecting the perspective that retailers' wholesale input costs could reflect a book build over time.[57]

6.15. The focus on the link between expected (rather than realised) supply costs and retail pricing also avoids the need to adjust for the effects of, say, demand or supply shocks or other factors outside a gentailer's control that impact margins after having set retail prices.

6.16. A key design question to be resolved, signalled in the discussion from paragraph 3.73.64 on, is what might be appropriate ways for a gentailer to define what its relevant time horizon is, and how expected cost of supply is determined, when it explains the link between the expected cost of supply and prices.

6.17. The Authority currently considers that expected costs can be observed from ASX and OTC contracts of relevant durations that look through any near-term volatility (if that is consistent with a retailer's strategy). This seems consistent with the submissions from gentailers and their experts (see paragraphs 3.61-3.63). The Authority is interested in submitters' views on these points, which will also need to be considered during the design of RPCA guidance.

6.18. To emphasise, the Authority does not expect that retail prices must be or are best linked to short duration ASX contract prices and agrees that retailers managing wholesale price risk[58] for their customers (price smoothing) has value to many customers and is a strategy consistent with workable competition.

What we propose the assessment involve

6.19. Each gentailer would have to regularly demonstrate (and certify there is) an economically justifiable link between expected cost of supply and retail offers

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[56] Electricity Authority, "Internal Transfer Price and Retail Gross Margin post implementation review", 7 Nov 2024, para 5.5.

[57] ACCC, "Restoring electricity affordability and Australia's competitive advantage: Retail Electricity Pricing Inquiry—Final Report," June 2018, 109, https://www.accc.gov.au/system/files/Retail%20Electricity%20Pricing%20Inquiry%E2%80%94Final%20Report%20June%202018_0.pdf.

[58] Both market fluctuations and supply shocks.

(including retail pricing for existing customers) with respect to its domestic and small business consumers.

6.20. As much as possible, the approach seeks to leverage existing processes and information.

6.21. For example, gentailers already make decisions on retail pricing, considering the cost of supply, the effects of location (differences in losses and network costs), the use profiles and preferences of their customers, different tariff structures, etc.

6.22. The Authority has also commenced collecting detailed monthly information from retailers with respect to domestic and small business consumers, including retail tariffs.[59]

6.23. The large gentailers would be expected to undertake the RPCA for each of its retail brands, and for key retail segments.

6.24. The assessment involves comparing retail $/MWh to an expected cost of supply $/MWh. Our current view is that the method (to be detailed in the guidance) needs to cover:

- retail price offers for new customers and pricing for existing customers (tariffs expressed as $/MWh), by brand, key segment and location (eg, electricity distribution business (EDB) or some other reporting region)
- metering, levies and network costs, which differ by location
- an indicator of the cost of retailing per MWh, in the short run and long run
- an expected cost of supply benchmark with relevant shape and for an appropriate duration (based on relevant market transactions)
- any economically justifiable adjustment for differences between market-based cost of supply and self-supply (transaction costs, risk premia)
- weightings applied to derive summary measures.

6.25. The assessment derives a residual energy cost, which can be compared to an observable market-based benchmark for the expected cost of electricity supply, or alternatively a retail gross margin (covering the cost of operating the retail business and any profit) from the difference between retail prices (less non-energy cost) and market-based expected cost of electricity supply.[60]

6.26. An important step in the design process will be to define an appropriate cost of supply benchmark, including a time horizon, based on a sound economic rationale.[61]

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59 Electricity Authority, “Retail market monitoring notice” 17 March 2025, https://www.ea.govt.nz/documents/6728/Retail_market_monitoring_notice.pdf.

60 The Authority acknowledges that Code (cl13.259) already contains RGM provisions, and these would need to be amended to reflect the proposals in this options paper. This is set out in more detail in Chapter 11

61 NERA (for Meridian) noted retail profitability could be assessed using current forward rates, suggesting this would measure whether a generator retail tariff would be profitable for a standalone retailer with no historical purchases of risk management products (para 91). It argues however that, to meet the no subsidy rule, this approach would require ‘gentailers to unwind the current approach to long run price smoothing and price on a

See paragraphs 3.73 to 3.75 for a discussion of potential candidates – the Authority welcomes stakeholders' feedback on these or other options.

Approach recognises wider considerations

6.27. Broadly speaking, a gentailer's retail prices per MWh (less non-energy costs) would be expected to sit at some margin above their cost of supply, with this gross margin covering retail costs.

6.28. If this is not the case, it raises a flag that the gentailer may be discriminating on the price of risk management contracts or setting its retail prices below cost.

6.29. But, as discussed in paragraphs 3.64 to 3.82, in practice a range of factors mean that the assessment cannot offer a brightline pass or fail result, e.g. so that any fail would immediately lead to some enforcement action. This is because there may be good reasons for slim or negative margins in the near term. However, a persistent pattern would be cause for concern as it could indicate ongoing price discrimination. This could trigger the Authority's normal compliance processes, which could in turn lead to enforcement by the Rulings Panel.

6.30. For example, it is possible that a retailer:

- seeks to look through periods of scarcity (or abundance) in setting retail prices because managing spot price risk for consumers is a retail service
- is offering discounts to grow (invest in) market share, or
- may be investing in customer retention to save on the recruitment cost of replacing lost customers.

6.31. A retailer must ultimately recover its costs of retailing, including an economic return, and so retail pricing needs to provide a margin over the cost of supply over some longer time horizon.

6.32. To avoid doubt, in proposing to rely on ASX and OTC contract prices as indicators of the expected cost of supply, the Authority is not suggesting that retailers would be 100% hedged. Rather, we expect traded hedge prices reasonably reflect the expected future spot price of supply and so provide useful measures to compare retail prices to.

6.33. It is also not intended that the assessment method becomes the template for a gentailer's (or independent retailer's) risk management or retail pricing strategies. Retailers have different risk management portfolios and pricing strategies, reflecting their financial situation, risk preferences, competitive strategies, and customer profile. It is critical for competition that gentailers continue to make their own choices – albeit consistent with NDOs.

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more short-term basis' (para 94). The Authority considers a forward-looking approach does not at all preclude taking a longer view on expected cost of supply, e.g. see paragraphs 3.73-3.75.

The Authority agrees with Meridian (p34) that a key step of the design process will be to define 'observable market rates' and avoid the risk that the RPCA adopts a cost of supply measure that is inefficiently volatile by not reflecting consumer preferences for any (economic) price smoothing.

Proposed disclosure requirements

6.34. Gentailers would be required to regularly make and disclose their RPCA (every six months). RPCAs submitted as part of gentailers' annual reporting requirements would be subject to director certification. With details subject to development of the RPCA guidance, the disclosure would cover:

- a gentailer's overall assessment of the link between cost of supply and its retail prices and summary results by brand
- the key components which make up its summary results, likely:
    - weighted average retail prices per MWh by brand and key segment (offers for new customers, and prices for existing customers)
    - weighted average non-energy costs per MWh – network (transmission and distribution), metering, levies
    - expected cost of supply per MWh (with any economically justifiable adjustments capturing any reduced costs from self-supply)
    - estimate of short run and long run incremental cost of retailing per MWh
    - the resulting energy residual derived by subtracting (ii) and (vi) from (i) to compare to (iii) and resulting expected gross margins, derived by subtracting (ii) and (iii) from (i)
    - methods used and any data or aspects of the assessment method specific to a gentailer that the Authority cannot derive from existing retail or contract data disclosures.

6.35. The Authority would receive these disclosures from each gentailer and regularly prepare and publish a report on the RPCAs. It will follow up on any irregularities. Any irregularities may trigger the Authority's normal compliance processes.

6.36. The Authority's current view is that more detailed disclosure would not be necessary. The Authority expects to be able to draw on retail and OTC data that is now being disclosed to replicate and test gentailers' summary results if that were necessary, by applying the guidance and methods to be developed through technical engagement with stakeholders.

Process from here: developing guidance on methods and inputs

6.37. The Authority will develop guidance on particular details and key parameters for the RPCAs. The design process will involve seeking input from participants. RPCA guidance on methodology and key inputs will promote comparability and confidence in the measures.

6.38. The Authority would expect to publish any guidance on the recommended methodology for undertaking RPCAs by 30 April 2026. Chapter 7 sets out the proposed implementation pathway.

Interaction with the Commerce Act

6.39. The RPCA conceptually covers similar ground to margin squeeze theories of harm, which could also be considered under section 36 of the Commerce Act.[62]

6.40. The RPCA is intended to be economically consistent with those theories but is not the same. It is rather a specific regulatory test under a sector specific regime and focused on a particular competition risk (discrimination). The RPCA will therefore be developed in a way that is fit for purpose for this regime.

6.41. A key difference between the RPCA and section 36 of the Commerce Act is that the RPCA will not require any proof of substantial market power.

6.42. Separately the Commission of course retains its function of investigating whether conduct may contravene section 36 of the Commerce Act and taking enforcement action. The Commission may be informed by any outcomes of the RPCA in taking decisions to investigate parties for potential breaches of the Commerce Act. For clarity, problematic conduct under the RPCA does not mean that the conduct also breaches section 36 of the Commerce Act, and vice versa.

6.43. The Commission and the Authority expect to share information on these matters where possible to ensure that each is best able to exercise its separate jurisdiction.[63]

6.44. We intend to continue to engage with the Commission as we develop the RPCA to get the benefit of their experience and best practice.

Questions

Q11. Do you agree that by providing transparency on margins, the RPCA would materially improve stakeholders' confidence that retailers compete on a LPF for the long-term benefit of consumers? If not, why? Can you share any evidence that supports your view? How could we adjust the test to further improve confidence?

Q12. What impact do you think the RPCA will have on retail prices and incentives to invest in generation? How does this compare to the impacts you posited in response in the LPF Options paper? Can you share any evidence that supports your view?

Q13. How could the proposed approach to the RPCA be improved?

Q14. How often should gentailers make and disclose their assessment – should it be more or less frequent than every six months, and why?

Q15. Would it be sufficient for the Authority to provide gentailers with guidance on the methodology for the RPCA or should it be prescribed in the Code, and why?

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[62] See the Commerce Commission's "Misuse of Market Power Guidelines," March 2023, https://comcom.govt.nz/__data/assets/pdf_file/0014/311360/Misuse-of-Market-Power-Guidelines-March-2023.pdf.

[63] This can occur under section 99AA of the Commerce Act and section 47A of the Act.

Q16. If you do not support the RPCA approach, what would you propose instead to demonstrate compliance with non-discrimination principles?

7. Implementation pathway

7.1. This chapter sets out our current view about how the proposed principles-based NDOs should be implemented and then monitored.

The implementation pathway should be timely and practical

7.2. A key objective of the proposed measures is to support the confidence of market participants. In our view, we need timely implementation, appropriately staged, to achieve this. The need for timeliness is reflected in our redesign of the non-discrimination principles (detailed in Chapter 5) – particularly the removal of the requirement for gentailers to specify an internal hedge portfolio – and in our consideration of monitoring, enforcement and escalation in the chapters that directly follow.

Timeline

7.3. The proposed commencement date is 1 July 2026. This date balances getting the new requirements in place as soon as reasonably practicable, with the reality of gentailers needing to engage with material changes to their business processes. Gentailers will need to ensure they have appropriate systems and processes in place for their directors to certify compliance with the proposed measures. A 1 July commencement date also aligns with the gentailers' financial year, which avoids unnecessary compliance costs. We propose requiring gentailers to publish an implementation plan on 1 July 2026. This will provide transparency on their approach to complying with the NDOs.

7.4. The first RPCAs would also be required to be provided to the Authority on 1 July 2026. This step is intended to ensure that gentailers can demonstrate compliance with the third limb of Principle 1.

7.5. In February 2027, gentailers will, under the proposal, be required to publish interim reports demonstrating how they have met the non-discrimination principles. The Authority intends to review the interim reports. We will provide views on areas of concern or particular focus for gentailers to consider incorporating into their annual reports.

7.6. Gentailers will also be required to self-report any breaches of the NDOs, providing insights into the number of complaints, the nature of those complaints and their resolution. Breaches must be self-reported within 20 working days after the gentailer becomes aware of the breach.

Table 2: Proposed Implementation timeline

Proposed Dates	Implementation Steps
March 2026	Code change published
April 2026	RPCA guidance published
1 July 2026	Commencement date First RPCA provided to the Authority, six monthly thereafter Gentailer NDO implementation plans to be published
February 2027	Interim reports provided to the Authority (and published within 5 working days) Second RPCA provided to the Authority, as part of interim reports Authority to subsequently consider whether to make RPCA guidance mandatory
April 2027	Electricity Authority feedback on interim reports[64]
September 2027	Annual reports provided to the Authority (and published within 5 working days) Third RPCA provided to the Authority, as part of annual reports
February 2028	Fourth RPCA provided to the Authority, as part of ongoing requirement for half-year RPCA reporting

Disclosure and self-reporting

Previous proposal

7.7. In the LPF Options paper, the proposed approach to monitoring compliance was:

> "given the discretion available within a principles-based regime, a substantial monitoring and reporting regime would be required to incentivise and demonstrate compliance, including the following.
>
> (a) regular self-reporting by Gentailers, setting out in detail how they have complied with the principles, and any instances of non-compliance
>
> (b) requiring all hedges 'sold' to Gentailers' internal retail arms (regardless of the formality of this transaction) to be disclosed through hedge disclosure obligations or otherwise, including a granular breakdown of baseload, peak and super-peak hedges

64 Our preference is to be transparent about this feedback, at least in terms of the issues raised. We will assess how best to communicate our views to all stakeholders at the time, acknowledging that some feedback may be best provided confidentially to the relevant gentailer only.

(c) where a Gentailer does not provide a conforming response to a request for hedge cover, a requirement for the Gentailer to explain the reasons why

(d) external audit or Director certification requirements.

As well as monitoring compliance with any new regulatory requirements, we would also monitor the broader outcomes observed in the market, such as wholesale and retail prices."

Feedback

7.8. A number of submitters (Consumer, ERANZ, Entrust, Lodestone, MEUG, Link Economics, Fonterra, Octopus, IRA) emphasised that a principles-based approach would rely on effective and robust monitoring. CSA for Meridian argued that a principles-based approach leaves room for interpretation, which makes monitoring challenging. Some submitters (EPOC, EnergyLink, Helios) also emphasised the need for monitoring of market prices, including offers and bids. Fonterra also recommended shortening the stocktake intervals from six months to quarterly for an initial period, to ensure immediate compliance and effectiveness.

7.9. IER were in favour of director-level certification of compliance with non-discrimination principles. They also argued that this self-certification should be strengthened with some independent assurance/audit requirements, backed up with penalties for non-compliance. ERANZ supported accountability and transparency but wanted clear guidance from the Authority on how director certifications would be evaluated. They were concerned that if the Authority retains the ability to second-guess directors' methodologies after the fact it could create legal and reputational risks for directors acting in good faith.

Our response

7.10. We have removed one of the key aspects of the proposed NDOs that was open to interpretation (gentailer internal hedge portfolios). Despite this, significant discretion remains within a principles-based regime. A substantial disclosure and self-reporting regime is therefore still required to incentivise and demonstrate compliance, as well as providing confidence to buyers and the broader sector that hedge trading is appropriately supporting competition. The disclosures and self-reporting would have two purposes:

- shining a light on gentailer behaviour and transactions to directly provide more information to all stakeholders, which better allows them to form judgements about how the market is performing
- surveillance of market behaviour to determine whether any further action by the Authority is warranted.

7.11. We propose that gentailer disclosure and self-reporting obligations include the following:[65]

[65] If this proposed Code change to introduce NDOs goes ahead, we will review the proposed NDO related disclosures against all other existing relevant disclosure requirements. This will ensure that the aggregate

- a comprehensive gentailer self-reporting regime for breaches of the principles – with gentailers required to report breaches within 20 working days[66]
- establishing and maintaining records that better allow all parties to understand the capacity of gentailers to offer risk management contracts, including regular disclosure of:
    - the forecast total capacity of the gentailer to offer risk management contracts
    - their forecast uncommitted capacity to offer risk management contracts
    - monthly electricity supplied the past 12 months, including total retail electricity sales and total forward contract volumes
    - methodologies for the pricing of risk management contracts
- expected monthly electricity supply over the next 3 years, ie, its net customer growth and churn projections, including key drivers and assumptions
- comprehensive disclosures regarding requests for risk management contracts by buyers and offers provided in response, including:
    - reasons for a gentailer either not providing an offer in response to a request from a buyer; or providing a non-conforming offer in response to a request from a buyer (with reference to available capacity under where applicable). This is proposed to be collected through an updated cl 2.16 notice.
    - any reason for discriminating between buyers, or against buyers in favour of a gentailer's own internal business units, for the purposes of principle 1.
- annual reports, certified by directors, demonstrating how the gentailer has met the non-discrimination principles, including reference to the records referred to above.

7.12. We remain of the view that director-level certification of compliance is an important mechanism for ensuring compliance with non-discrimination obligations. Director-level certification will ensure that appropriate non-discrimination policies are adopted across gentailers.

7.13. We note ERANZ's submission that the Authority should provide clear guidance on how director certifications should be evaluated. Director certifications will not be evaluated *per se*. Directors are required to certify, to the best of their knowledge and after making all reasonable inquiries that the gentailer has complied with the NDOs. The Authority would expect the annual reports to be able to demonstrate clearly the

requirements work as a package and are efficient. We do not want to require gentailers to disclose the same information through two separate processes.

66 The LPF Options Paper distinguished between self-reporting of material and non-material breaches. We are now proposing to make the self-reporting obligation consistent with the Electricity Industry (Enforcement) Regulations 2010 (regulations), so that all breaches of the NDOs are to be reported in the same way (ie, without distinguishing between material and non-material breaches). However, rather than requiring reporting as soon as possible (as required by the regulations), we are proposing to give more clarity by requiring breaches of the NDOs be self-reported within 20 working days.

basis on which directors provide their certification, ie their reasonable inquiry. Should those linkages be unclear, and/or if there are gaps in the record keeping requirements, the Authority would consider the most appropriate next step.

7.14. In addition, the extent to which gentailers can provide evidence of their approach to compliance would be a factor in the Authority's approach to preliminary assessment of an alleged Code breach, investigation and any other enforcement mechanism of the non-discrimination obligations.

7.15. In addition to disclosure and self-reporting, in our view, there should be a genuine prospect of enforcement action to incentivise compliance, both with the non-discrimination principles themselves, and with any process requirements that support compliance and assurance, eg, the requirement on directors to make reasonable inquiry. Our view is that this revised proposal is substantially better suited to enforcement than the previous proposal set out in our LPF Options paper, reflecting:

- the simplification of the core non-discrimination requirement, particularly through the removal of the requirement for gentailers to develop a robust internal hedge portfolio (which inevitably introduced uncertainty and ambiguity that was not well suited to enforcement)
- the Authority's commitment to provide key guidance and feedback during the implementation of the new regime
- the option for the Authority to tighten specific aspects of the principles to reflect that feedback (as opposed to a binary distinction between principles-based and prescriptive non-discrimination obligations – see Chapter 8 below).

7.16. Any enforcement action by the Authority would follow our normal compliance processes, with the ultimate decision maker on an alleged Code breach being the Rulings Panel, if an alleged Code breach proceeded this far.

Questions

Q17. Is the proposed implementation timeline achievable?

Q18. Should the Authority consider adding or removing any particular steps, or providing more or less time at any point?

Q19. Does the proposed approach to implementation provide the right balance between certainty, transparency and flexibility to allow gentailers to demonstrate their compliance with the non-discrimination obligations, and to provide an appropriate basis for enforcement action if they do not?

8. Escalation pathway

8.1. This chapter considers the escalation pathway from the proposed principles-based NDOs in light of submissions and the redesign outlined in this paper.

8.2. The LPF Options paper set out a three-step progressive approach to level playing field regulation.

8.3. We are no longer proposing a stepped approach. Instead, our proposal is to implement and enforce NDOs, starting with a principles-based approach supported by guidance on how we would expect gentailers to comply with the non-discrimination principles (see Appendix B). The guidance is intended to exist as a separate document, without being provided for in the Code itself, but could be incorporated into the Code at a later point if necessary.

8.4. We now see escalation from non-discrimination principles to more prescriptive rules occurring on a spectrum. Parts of the principles-based obligations will likely be strengthened over time as best practice is established or any issues arise, rather than needing to completely re-write the whole regime.

8.5. The Authority is not proposing to implement Step 3 (mandatory trading of gentailer hedges) as an escalation. The Authority will evaluate the overall impact of its interventions including: the NDOs, the development of the standardised flexibility products, and any market making interventions. If further escalations are required, these would need to be adapted to the nature and size of the problem.

Steps and escalation

Previous proposal

8.6. The LPF Options paper outlined a roadmap for the implementation of non-discrimination rules. The roadmap would apply to all gentailers' hedge contracts and equivalent financial instruments, including the ITPs. The three steps were as follows:

- Step 1: Principles-based non-discrimination requirements, including more detailed ITP design principles
- Step 2: Non-discrimination requirements prescribed in detail
- Step 3: Mandatory trading of gentailer hedges.

8.7. Step 1 would introduce principles-based non-discrimination obligations for gentailers into the Code, covering all hedge contracts (and equivalent financial instruments). The second step, if triggered, would be to introduce more detailed (prescriptive) rules governing gentailers' interactions with buyers of hedge products. The aim would be to remove (or at least significantly reduce) the room for discretion that would exist under principles-based rules.

8.8. Our intention was to wait until after the early disclosures from gentailers under the principles-based regime before considering:

- whether more prescriptive rules were needed
- the drafting of these prescriptive rules.

8.9. The third step of our proposed roadmap, if triggered, was to require gentailers to sell and purchase all their hedging via a market platform. This is the most severe form of non-discrimination requirement, effectively preventing gentailers from internally hedging. This would be a significant vertical disaggregation with selling and buying through a market mechanism specifically designed to prevent discrimination.

8.10. As we were seeking feedback on the proposed new non-discrimination obligations for the first time in February, we did not specify escalation triggers for step 3 at that point.

Feedback

8.11. Submitters were split in their feedback on the escalations. One group, largely independent retailers and commercial consumers, saw the escalations as appropriate, and generally emphasised the need for clear triggers. This included Lodestone Energy, Fonterra, Consumer NZ, Entrust, Electricity Engineers Association, and Helios. A subgroup argued for accelerated implementation, including Octopus Energy, 350 Aotearoa, the Independent Electricity Retailers and Pulse Energy. For example, the IER argued that Step 1 should only be a temporary measure while the rules for Steps 2 and 3 are developed. Neoen argued for a staged approach on a clear timeframe.

8.12. The other group, largely gentailers, were opposed to the escalations, for a variety of reasons:

- Genesis raised the risk that the “failure” of Step 1, could just be the result of flawed policy, rather than a market issue.
- Contact raised capital requirement issues with Step 3, argued that hedge prices would converge on ITPs (reducing competition), and highlighted the risks of unintended consequences.
- Meridian’s expert (CSA) was concerned that individual gentailers would be subject to Steps 2 or 3 due to the non-compliance of other gentailers.
- Energy Resources believed that Step 3 would have a negative impact on investment and raise consumer prices.
- Mercury argued that Step 3 was not a progressive escalation and would remove all the benefits of vertical integration and result in increased consumer prices.
- BEC made many of the same arguments outlined above. They also raised concerns that rules under Step 2 would be too rigid to capture the nuances of the market and gentailers' individual circumstances. This could lead to errors, stifle innovation in trading practices, and increase regulatory burden.

8.13. There were a few submitters with views in between these two groups. Energy Link argued that information generated by Step 1 could be used to better shape/target escalation options. Nova suggested a gradual implementation of Step 3, with a number of pre-conditions.

8.14. In discussion with the Authority Board and Task Force representatives, some submitters noted that it was Step 3 that caused their primary concern about generation investment incentives.

Our response

8.15. We acknowledge the criticisms of the escalations from Step 1 to Steps 2 and 3.

8.16. Given this feedback, we have reconsidered our approach to escalation, acknowledging:

- the redesign of the approach to NDOs
- LPF remedies operate as part of a package of reforms, and that any escalation should be consistent with that package to be most effective.

8.17. We are also not proposing an escalation to Step 3 as this would undo most of the benefits of vertical integration. Given that we have removed these elements of the proposal, many of the issues identified by submitters no longer apply.

Revised proposal

8.18. Our current proposal is materially different from the Step 1 previously proposed in the discussion document. The key difference is that we are no longer proposing to use ITPs or the construction of a hypothetical hedge portfolio. Instead, our proposal has a RPCA as the key intervention for demonstrating non-discrimination on price terms alongside non-discrimination obligations on conduct.

8.19. In practice this means a core part of the escalation to Step 2 under our previous proposal – prescribed internal transfer arrangements – no longer exists. In addition, we received a range of feedback around both:

- the benefits of keeping any non-discrimination framework adaptable
- the value of clarity, ie, specifying exactly what is required.

8.20. We have also prepared draft guidance on how we would expect gentailers to comply with the NDOs (see Appendix B). We intend to finalise this guidance, following consultation with stakeholders, before any Code change takes effect. The guidance is intended to exist as a separate document, without being provided for in the Code itself, but could be turned into Code at a later point if necessary.

8.21. Initial guidance in relation to the RPCA will also be developed and published in advance of the assessment following an additional consultation process.

8.22. In this context, a binary distinction between a principled or prescriptive approach is no longer helpful. We now see escalation from non-discrimination principles, under the current proposal, to more prescriptive rules occurring on a spectrum. Parts of the principles-based obligations will likely be strengthened over time as best practice is established or any issues arise, rather than needing to completely re-write the whole regime.[67]

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[67] There are parallels with the approach to Distribution Pricing Principles. These are for EDBs to interpret and implement in setting network pricing. Over time the Authority has moved from talking and encouraging, to scorecards and league tables, to detailed guidance, open letters (setting specific expectations), and is currently consulting on Code changes.

8.23. More specifically, we expect that the RPCA would evolve after the Authority has had the opportunity to analyse the first rounds of data. This could take the form of further guidance or Code change (including codifying existing guidance) as appropriate.

8.24. We also expect that greater levels of prescription can be used to deal with any serious inconsistencies or difficulties in interpretation of the non-discrimination principles.

8.25. Many submissions conceptually supported escalation, but requested clearer, more objective triggers. While we understand those submissions, we do not consider that specific triggers for greater prescription are useful given it is not proposed to be a binary escalation. Rather, any potential tightening of the NDOs should be considered with reference to the information available to the Authority at the time, and against an appropriate set of questions.[68]

8.26. Our preference is to develop the regime by producing further guidance or by adding more prescription through Code amendments to parts of the regime in response to issues that arise. This is an incremental approach that may result in some elements of the NDOs remaining as high-level principles and others becoming much more prescriptive.

Possible further escalation – effectiveness review of reform package

8.27. We acknowledge the criticisms of Step 3 from the LPF Options paper. We accept the submission that Step 3 as proposed would put significant benefits of vertical integration at risk, and that a change of that magnitude has high risks of unintended consequences.

8.28. Our new proposed approach is to:

- focus on refining the NDOs quickly (ie, adding more prescription) where any ambiguities or concerns arise
- enforce where required to ensure the NDOs are being given effect to
- consider any material changes to the NDOs (regardless of how prescribed they are) as part of a broader assessment of the success of all interventions in hedge markets currently being considered or implemented including work in relation to the standardised flexibility products and the review of market making.

8.29. We currently consider that it would only be sensible to consider any significant escalation or broader change after undertaking an effectiveness review of our broader pro-competition reform package. This would commence following the receipt of gentailers' first tranche of annual disclosures. At that point, we would expect to have substantially more information on how well all aspects of the hedge market are

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[68] For example, in relation to the relevant aspect of the Principles:

- Has a genuine ambiguity been identified?
- Has a best practice approach emerged that all gentailers should follow?
- Is there still a benefit in allowing each gentailer to adapt the Principle to their specific circumstances?

operating and would have been able to implement any flexibility product or market making reforms from current or signalled reviews.

8.30. In addition to information made available under the NDOs, we expect greater monitoring of the OTC market to increase understanding of the effectiveness of the wider package of measures and detect potential non-compliance with the NDOs. This would include the Authority receiving information on the processes leading to the formation of OTC contracts, including offers, bids and agreed prices (as outlined in the recently updated clause 2.16 information notice).[69] This would take place alongside other monitoring of the hedge markets and assessments of its competitiveness.

8.31. At that point, we would also be able to take account of any reforms that the Government has developed and implemented as a result of its review of electricity market performance.

8.32. In summary, we are no long proposing to implement Step 3 as it was set out in the LPF Options paper. If further escalations are required, these would need to be adapted to the nature and size of the problem.

Questions

Q20. Do you support the revised approach of incrementally creating more specification for NDOs or the RPCA as required? Why or why not?

Q21. What are your views on the proposed escalation pathway?

[69] Electricity Authority, "Improving visibility of competition in the OTC contract market: Decision paper," 16 September 2025, https://www.ea.govt.nz/documents/8368/Decision_paper_-_Improving_visibility_of_competition_in_the_OTC_contract_marke_81Cxszb.pdf .

9. Power Purchase Agreements

9.1. The purpose of this chapter is to set out our current view on how the proposed NDOs will impact on the market for Power Purchase Agreements (PPAs). The Authority continues to see a deeper PPA market as an important component of enabling new investment in intermittent generation.

9.2. The non-discrimination principles will apply to gentailers when they are selling firming to independent generators or intermediaries providing sleeving. The good faith principles should also be helpful. We see the super-peak product as a useful product for trading some forms of firming. We intend to convene a co-design group, similar to the Standardised Flexibility Product Co-design Group to consider the specific flexibility needs of independent generators, and how these could be met through new product development.

Context – the role of PPAs and the Task Force's separate PPA workstream

9.3. PPAs are contracts sold by a generator or developer, linked to a specific generation development, generally for a term of 10 years or more. The volume of energy sold through the PPA is directly linked to the output of the generation. PPAs are generally used to underwrite the financing of the generation development, so play an important role in facilitating new investment.

9.4. Where a PPA relates to intermittent generation (e.g. solar or wind), and the PPA buyer is an end user (not a gentailer), the buyer will likely need the PPA supplied electricity to be 'firmed', i.e. backed by flexible electricity supply to ensure that the buyer has access to electricity whenever needed.[70]

9.5. The Task Force set up a separate stream of work on PPA firming (1A) to consider this point further. Would it promote further efficient generation investment if the Authority introduced specific Code requirements around the supply of firming for PPAs by the four large gentailers? To properly consider this question, the Authority set out a view on the current state of the PPA market in New Zealand, and particularly on the various potential headwinds to a deeper PPA market. The Authority released two papers on the topic:

- a working paper in January 2025 entitled "Entrant generators – context, headwinds and options for power purchase agreements"
- an update paper in May 2025 entitled "Enabling new generation entry – Options for power purchase agreements" (the PPA update paper).

9.6. There are overlaps and crossovers between the PPA and LPF work – both are effectively trying to ensure that New Zealand's flexible generation base is able to be accessed in a way that best promotes generation and retail market competition and investment.

70 As opposed to only having access to electricity when the sun is shining or the wind is blowing.

Previous proposal

9.7. While the LPF Options paper discussed PPAs in places, it did not make specific proposals about PPAs or ask specific questions about PPAs. However, the PPA update paper suggested that the non-discrimination proposals could be modified to support generation entry (via access to firming for PPAs).

Feedback

9.8. Some submitters provided some information or commentary on PPAs. This section also includes some material from submissions on the PPA working paper.

9.9. Energy Link stated that there is not yet enough information to know if independent generators face barriers to entry not faced by gentailers because we are less than one year into the post-Tiwai-closure era, and there is insufficient data with which to draw any firm conclusions. In their view, this issue needs close monitoring, and potentially also development of options that could be implemented quickly and efficiently, if over the course of the next two to three years it does turn out there is a competition issue in this segment.

9.10. Some submitters with an interest in selling PPAs were generally supportive of the LPF measures, because they see them as deepening the hedge market which would enable aggregation of PPAs with firming products to match demand (Helios, EVA Marketplace, Neoen).

9.11. The Independent Generators' Association (IGA) and Octopus suggested that NDOs need to also apply to transactions where the gentailer is buying an electricity contract.

9.12. Others saw shortcomings in the LPF proposals that made them irrelevant to PPAs. The IGA and Slowjam pointed out that the gentailer's notional hedge portfolio may not include 10-15 year contracts and so would not create any obligations to purchase these from independent operators.

9.13. In a different take on hedge terms, Nova pointed out that parties exposed to intermittent generation output (being either the generator or buyer of a PPA) need to hold significant levels of capital to avoid insolvency under adverse generation and pricing conditions. If a gentailer builds new generation, they rely on maintaining their retail base for at least the first 7 years or so to service debt obligations. In their view, independent retailers are only interested in shorter term contracts, typically around 3 years because of the risk of being 'out of the money' and the capital they need to underwrite longer term hedges or PPAs. If the gentailers are required to sell hedges on equal terms, then independent retailers must be prepared to sign 5-to-7 year hedges and hold adequate capital to support those.

Our response

9.14. The evidence on the scale or source of challenges in negotiating PPAs is quite mixed. From the submissions on the PPA working paper, it seems that PPAs for baseload generation (eg, geothermal) are relatively straightforward to negotiate with the gentailers. Independent generators seem to primarily encounter difficulties with negotiating PPAs for intermittent generation, such as solar or wind. This suggests that the issue is not PPAs, so much as the lack of firming capacity in the system.

9.15. A complication in the analysis is that there is no agreement on exactly what a firming product is, or rather no single firming product. Some generators simply want a super-peak product to firm evening demand, others want night-time coverage and others want more bespoke products.

9.16. There is a risk that a more specific mechanism for ensuring independent generator access to firming capacity than NDOs could be unhelpfully rigid, or risk competitive distortions and potentially favour some market participants or generation technologies over others. That is a core reason why the PPA update paper confirmed that the Authority favours access mechanisms for responding to PPA firming needs, rather than specific allocations of firming. The Authority should remain neutral as to which parts of the market (retailers, generators, brokers or others) are best placed to aggregate firming with other generation capacity. Firming capacity is best allocated through market mechanisms that are open to all market participants.

9.17. Slowjam's submissions usefully highlighted what the *Australian National Electricity Market wholesale market settings review* describes as the 'tenor gap', which it considered to be a persistent barrier to new investment.[71] The 'tenor gap' is the mismatch between the long-term contracts needed by sellers to finance capital-intensive assets (often 10-30 years) and the short-term contracting of buyers (typically 3-7 years). This gap is driven by a broad suite of uncertainties: technological, regulatory and demand related. Some of the submissions highlighted elements of the tenor gap.

9.18. We acknowledge that tenor gap is an issue. There is no simple market-based solution to this, but a deeper market for PPAs is likely helpful, ie, even if a generator cannot secure a 30-year contract, it is useful that they have a high degree of confidence that they will be able to enter into a series of shorter term PPAs over the life of a new generation asset. We welcome any feedback on this point.

9.19. In terms of providing specific firming support for PPAs, our previous NDO proposal linked access obligations to the gentailer's internal hedge portfolio. So, if they were effectively offering long-term firming to their own retail function, they would need to also offer that to new generators.

9.20. The shift away from requiring gentailers to specify an internal hedge portfolio has removed some of the submission concerns about the content of that portfolio and hedge terms, but it also removes this potential anchor for requiring gentailers to offer long-term firming.

Revised proposal

9.21. We are proposing to ensure that the definitions used in the NDOs are broad enough to also cover gentailers when they are responding to requests to supply firming to

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[71] Tim Nelson, Paula Conboy, Ava Hancock and Phil Hirschhorn, National Electricity Market wholesale market settings review (August 2025)

competing generators. The non-discriminatory supply principles will apply to anyone who is seeking a firming product to match a PPA and ensure, for example, that industrial customers are not favoured over other buyers in the allocation of firming capacity.

9.22. The good faith obligations may be useful in ensuring that gentailers behave reasonably towards sellers of PPAs.

9.23. The new super-peak product is an important mechanism for trading firming capacity. Our broader proposals to strengthen voluntary trading in the product, and for market making if this does not occur, could improve both pricing and access to that shaped flexibility product. Submissions on the voluntary mechanism closed on 30 September and proposals on market making will be released for consultation in November. We also acknowledge that the super-peak product may not be relevant to many independent generators seeking firming products.

9.24. The Authority remains committed to encouraging more and faster generation investment and improving PPA uptake. We expect that this may require something more than the revised NDOs are able to provide in terms of the assurance re access to firming that new generators are seeking.

9.25. As next steps:

- We will consider seeking more detailed information about all requests for firming received by gentailers from independent generators. In doing so we have two aims:
  - better understand whether the anecdotal problems described to date are, over time, showing more common features that may be better suited to a further specific intervention
  - keep pressure on the gentailers – we will be watching closely and expect all requests for firming from new generators to be appropriately prioritised.
- Noting that there is some market interest in further firming options,[72] we intend to convene a co-design group, similar to the Standardised Flexibility Product Co-design Group, to consider the specific flexibility needs of independent generators, and how these could best be met through product development. We would welcome expressions of interest from any interested parties that want to be part of that conversation but were not members of the previous Co-design Group.

Questions

Q22. Do you have any feedback, including suggestions for improvement, on the way that the NDOs will affect buyers seeking firming for PPAs?

Q23. Would it be useful to convene a co-design group to consider a range of flexibility products that suit the needs of independent power generators?

[72] Genesis Energy, "Genesis engaging with market on short-term flexibility products," media release, 1 September 2025, https://www.genesisenergy.co.nz/about/news/genesis-engaging-with-market-on-short-term-flexibility-products.

10. Virtual disaggregation

MDAG previously recommended developing a blueprint for virtual disaggregation

10.1. MDAG was specifically concerned about the risk of some parties having “the scope and incentives to exercise market power in the provision of longer duration flexibility products”.[73] This risk came about from the “concentration of control of flexible supply resources”,[74] particularly where further thermal generation exits from the market.

10.2. In this context, MDAG recommended that if structural options are judged to be necessary to address competition issues in flexibility services, ‘virtual’ break-ups would be much better than divestment of physical assets. Virtual break-up options would use financial contracts designed to mimic the effect of physical disaggregation, but ownership and generation dispatch rights would remain unchanged. This means that there should not be any loss of coordination efficiencies on river chains.

10.3. MDAG suggested an option would be to create more effective competition in flexible supply by allocating (by auction) a significant tranche of flexible contracts from the primary holders of flexible supply (Meridian and Mercury) among wholesale market participants. Financial contracts can alter the incentives on parties with flexible generation. For example, a party that has an underlying incentive to withhold flexible generation from the market could have very different incentives if its contract position turns it into a net buyer in the spot market in the relevant time intervals. The design of contracts and their volumes would require detailed analysis.

10.4. MDAG also recommended that the Authority develop a high-level outline of ‘virtual disaggregation’ to ‘put in the drawer’ ready for use if other measures are not effective. If a structural solution is ultimately required to address competition problems in flexibility services, it should be put in place with the least possible delay. That means some initial scoping work as a precautionary step, even if it turns out structural options were not ultimately needed.

Previous proposal

10.5. Feedback was received on MDAG’s proposal, and in light of that, the LPF Options paper presented an updated proposal for the Mandatory Supply of Firming (MSOF). MSOF directly targets market power by requiring relevant generators to offer a specified volume of financial products (firming contracts) that are linked to their generation supply capability. This approach focuses on addressing market power at its source. The MSOF outline built on the MDAG work but it was not a preferred backstop measure under the LPF proposals.

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[73] Market Development Advisory Group “Price discovery in a renewables-based electricity system: Final recommendations paper,” December 2023, 95, https://www.ea.govt.nz/documents/4335/Appendix_A2_-_Final_recommendations_report.pdf.

[74] Ibid, 165.

Feedback

10.6. Less than half of submitters commented on the virtual disaggregation proposal in the appendix of the LPF Options paper. A few of these submitted that the proposal in the LPF Options paper (or the wider non-discrimination proposals) were based on misunderstandings of the MDAG report. There were a variety of views on what those misunderstandings were:

- Contact stated that the LPF Options paper misrepresented MDAG’s intentions with virtual disaggregation as it described the problem differently to MDAG, who focused on the ability to manipulate volatility in the spot market and deter new entry. The LPF Options paper also proposed implementing this solution ahead of a finding of market power, which was key to MDAG’s proposal.
- Nova pointed out that the critical context for MDAG’s proposal is a 100% renewable market, where almost all storage is in the form of hydro power.
- Meridian is of the view that non-discrimination is a form of virtual disaggregation (but of a vertical kind, rather than horizontal) that will chill incentives to invest in flexible generation resources, unlike MDAG’s proposal.

10.7. The Mercury panel endorsed many of the above characterisations of MDAG’s work but did not comment specifically on the virtual disaggregation proposal in the LPF Options paper.

10.8. Genesis was opposed to virtual disaggregation as in their view it incorrectly assumes that market power, rather than physical constraints, is the primary barrier to hedge liquidity.

10.9. Other submitters saw virtual disaggregation as either a complement to or substitute for non-discrimination:

- Octopus stated that virtual disaggregation is useful as a backstop along with wider non-discrimination provisions.
- SEANZ thought that the non-discrimination provisions could address the underlying issues that led MDAG to recommend virtual disaggregation. Virtual disaggregation could be useful if the non-discrimination measures do not work.
- the EEA had a similar view to SEANZ and thought that the threat of virtual disaggregation may reinforce compliance with a lighter touch regime. They suggested that if it remains on the table, it should be applied in a targeted way with clear triggers where there is evidence of harm or non-compliance.
- Unison thought virtual disaggregation would be useful if high market concentration persists.
- Helios do not support structural separation but believe that vertical disaggregation is a useful backstop.
- NZ Steel had concerns about both the current market and the non-discrimination proposals. They favour pursuing options involving virtual disaggregation and a minimum volume of traded generation (including firming).
- Pulse supported virtual disaggregation in the form that MDAG envisioned; specifically, the requirement that the large, incumbent gentailers are required to

offer a portion of their flexible supply capacity by a defined process and on approved terms effectively creating one or more additional sources for the supply of longer duration flexibility products.

10.10. Nova proposed an alternative to virtual disaggregation. In their view, it would be better for the relevant gentailers to have to sell PPAs for a proportion of their hydro schemes.

Our response

10.11. In our view, virtual disaggregation may be an appropriate response to issues of market power for market participants who hold scarce resources. This could be the case for the specific concentration of longer duration flexibility (the concern that MDAG was focused on), or for the more immediate concerns that the Authority has identified.

10.12. We set out a model of virtual disaggregation in our LPF Options paper. In our view that model continues to ask the right questions ie explores the key parameters of any proposed virtual disaggregation. We acknowledge though that there would be substantial further work to do on virtual disaggregation were it to become a genuine option for the Authority to implement, including being clear about which problems it was intended to solve.

10.13. At this point we do not consider that it is useful to do a further iteration of the February outline of virtual disaggregation. That reflects:

- our preferred approach to enforcement and escalation from principles-based non-discrimination obligations (set out in Chapters 5 and 8 of this paper)
- the broader context, in particular. the Government's response to the review of electricity market performance (including the work done by Frontier Economics).

10.14. We will update stakeholders on proposed next steps in relation to virtual disaggregation in early 2026, likely at the time we make our decision on the proposed level playing field Code change set out in this paper. The Authority remains committed to appropriately implementing MDAG's 2023 recommendations, but that must be done in light of the sector context, which has developed swiftly since publication of MDAG's report in December 2023 (and will likely continue to do so).

11. Internal Transfer Price disclosure requirements

11.1. The current ITP disclosure requirements in the Code were discussed in the LPF Options paper and submissions because they are relevant to the construction of an internal hedge portfolio – a core aspect of the LPF Options paper proposal – and the hedge market outcomes that the Authority is currently seeking to promote.

11.2. The ITP disclosure requirements were put in place to address concerns about even-handedness and potential margin squeezes. We believe that the proposals outlined in this paper better address those concerns than the ITP and note that we are no longer proposing an internal hedge portfolio. So, it is both appropriate and good regulatory practice to consider if the ITP disclosure requirements are still needed.

11.3. We are proposing to remove the ITP requirements from the Code and retain the RGM requirements, in the same subpart of the Code, only for independent retailers.

ITP and RGM disclosures were put in place to address even-handedness concerns

11.4. The 2019 Electricity Price Review[75] noted concerns raised by some stakeholders that gentailers may "be making excessive profits and favouring their retail arms to undermine competition", with a specific focus on the price for transferring electricity between their generation and retail businesses.

11.5. The Price Review panel recommended requiring that gentailers release information about the profitability of their retailing activities, including disclosing their ITPs. In response, the Authority looked at solutions to improve participant information disclosure, aiming to reduce information asymmetry in the market and increase transparency around retailer pricing practices.

11.6. The Authority amended the Code, which took effect on 30 November 2021, to require the disclosure of retail ITP information by gentailers. That Code amendment[76] also included a requirement to disclose RGMs by all retailers with over 1% of ICPs, which in the Authority's view at the time was likely to improve all parties' understanding of the competitive behaviour of retailers.

11.7. The ITP is the price that gentailers use for accounting purposes to split out their wholesale and retail functions, ie, the price of the electricity that their wholesale function "sells" to their retail function. The ITP section of the Code requires gentailers to disclose ITP information, with sufficient detail, to enable a reasonable person with an understanding of the wholesale market to determine how ITP prices are set.

11.8. The RGM is the remainder from electricity retailer revenue left over once the cost of electricity, metering, distribution, transmission services and levies have been subtracted. For gentailers, the cost of electricity is based on their ITP. The resulting RGM is the amount left to cover the retail cost of service and any retail profits (based on the assumed cost of electricity). The Authority said in its 2021 decision paper that "[t]his will inform the Authority on the pricing practices used within gentailers and

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[75] Miriam Dean, et al, "Electricity Price Review: Hikohiko Te Uira," May 2019, https://www.mbie.govt.nz/assets/electricity-price-review-final-report.pdf

[76] Sections 13.256 to 13.260 under Clause 5 of the Code were inserted.

establish whether they are providing electricity at below efficient market prices to their own retail arms".

11.9. The aim of both sets of information disclosure requirements was to help the Authority identify whether electricity markets are functioning competitively so trust and confidence in the wholesale market is strengthened. The Authority also aimed to provide assurance to participants about the competitive operation of the electricity market through improved transparency, by publishing key metrics on a centralised disclosure platform and facilitating their interpretation through appropriate benchmarks.

11.10. Currently gentailers are required to report annually on their ITP. All retailers above the ITP threshold have to produce an annual report on their RGM.

11.11. The November 2024 *Internal Transfer Price and Retail Gross Margin post-implementation review* found a general consensus that the current ITP and RGM reporting had limited usefulness, with gentailers using ITPs primarily for accounting purposes rather than setting retail prices. "We accept the consensus from all parties that provided feedback to us that the current ITPs are not a useful measure for any assessment that is seeking to better understand competition in the retail electricity market." Given this, the Authority accepted that the intent behind the relevant Electricity Price Review's recommendation (D3), and the subsequent introduction of the new section of the Code, had not been achieved.

11.12. The Authority noted at the time of the post-implementation review that it would need to reconsider the role of ITPs and the ITP/RGM disclosure regime.

Previous proposal

11.13. The LPF Options paper stated that more robust ITPs would be valuable as an important benchmark for any robust non-discrimination obligations. A new, robust ITP methodology would need to be informed by the implicit internal hedging strategy of gentailers, since these hedges (and their value) determine the actual ITPs. The timely implementation of a principles-based non-discrimination regime, with adequate guardrails, would put the onus on gentailers to demonstrate how their hedge offers (including pricing) to independent retailers/generators are 'substantially the same' as what they offer themselves internally.

11.14. An internal hedge portfolio is the same information that would be needed to derive a robust ITP. So, the non-discrimination regime proposed in February would have necessarily required work on more robust ITPs. The proposal would have required gentailers to disclose how they consider the relative costs of their generation and retail businesses, by explaining the nature and extent of their internal hedging in a granular way (for baseload, peak, super-peak, etc). This would provide a better information base against which offers to independent competitors could be compared.

Feedback

11.15. A number of submitters pointed out difficulties with ITPs including that:

- ITPs have not achieved their stated objectives (IER).

- ITPs are not determinative of retail prices as other factors such as input costs, and the market price are also taken into account (Contact).
- Reliance on observations of market rates to set ITPs is problematic if those market rates reflect market power or illiquid market conditions (the Mercury panel, Unison).
- There is no well-understood cost-based method by which to assess internal transfer prices for risk management products due to New Zealand's high degree of reliance on hydroelectric power and further, even if such costs could be estimated they would be likely to change dynamically in response to market circumstances (Houston Kemp (as part of the Mercury panel), Mercury).
- ITPs are not 'economically meaningful' as internal transactions represent transfers of value between different segments of a gentailer and so gentailers are indifferent as to their level (Houston Kemp, Mercury).
- Even with appropriate benchmarks for ITPs (such as the ASX), it would require considerable rule design to "make it work" (Mercury).
- Each gentailer has a different mix of generation, customers and contracts. Prescriptive ITP rules would be highly disruptive (Nova).

11.16. The IER questioned how the Authority proposed to create "a new, robust ITP methodology". In their view ITPs would be redundant once the non-discrimination rules are in place, as they would be replaced by actual contract pricing.

Our response and proposal

11.17. The Authority has assessed the feasibility of improving ITP methodologies and agrees with many of the criticisms that have been made. In particular, the difficulties of estimating the value of stored water are significant. We also agree that the exercise would require considerable rule design and testing, would come at significant cost and analytical difficulty. It would likely be contentious and time consuming, ie, the same reasons why we have moved away from requiring the gentailers to specify internal hedge portfolios as part of any NDO requirements.

11.18. The introduction of the ITP disclosure requirements was driven by concerns about even-handedness and potential margin squeezes. In our view, the proposals in this paper are much more likely to address both concerns.

11.19. The Authority is proposing to repeal the ITP reporting requirements because:

- the current ITPs are not achieving their objectives
- it would be very difficult and expensive to improve the ITPs (and may not be possible)
- this paper sets out much improved proposals for addressing the concerns that led to the creation of ITPs.

11.20. The Authority also proposes to remove the RGM reporting requirement for gentailers. We are confident that the purpose of those requirements will effectively be met for the gentailers by the regular RPCAs they will be required to perform and report on (see Chapter 7), if the proposed Code amendment is implemented.

11.21. We propose retaining the RGM reporting requirements for independent retailers. These requirements remain useful for monitoring purposes and include information that is not contained in the retail data notice. The RGM information will also assist in benchmarking independent retailer margins against information obtained through the RPCA.

11.22. Subject to the consultation and decisions made in relation to the proposed NDO Code, we are proposing to contemporaneously amend the RGM requirements accordingly to reduce the scope of participants they apply to, and to remove any reference to the ITP.

Questions

Q24. Do you support the proposal to revoke the ITP requirements for gentailers? What are your views on retaining the RGM reporting requirements for independent retailers?

12. Regulatory Statement for the proposed amendment

12.1. This chapter sets out the regulatory statement for the proposed introduction of NDOs for the four gentailers, as required under section 39 of the Act.

12.2. The regulatory statement must include a statement of the objectives of the proposed amendment, an evaluation of the costs and benefits of the proposed amendment and an evaluation of the alternative means of achieving the objectives of the proposed amendment.

12.3. The regulatory statement must be consulted on. Therefore, this regulatory statement contains the Authority's preliminary views, and we are interested in feedback from stakeholders on it.

Objectives of the proposed amendment

12.4. The objectives of the proposal are to promote competition in, and the efficient operation of, the electricity industry for the long-term benefit of consumers by:

- ensuring the even-handed supply of risk management contracts
- supporting the liquidity and competitive pricing of risk management contracts
- giving confidence to independent generators and retailers that they can compete on a level playing field with gentailers thereby facilitating investment in the electricity industry.

The proposed amendment

12.5. The objectives would be achieved, in part,[77] by setting conduct expectations on large gentailers, monitoring conduct, and enforcement in cases of non-compliance.

12.6. The proposal is that the Code specify that gentailers would be required to provide risk management contracts to buyers on a non-discriminatory basis.

12.7. A gentailer must not discriminate against buyers in favour of its own internal business units in access to or pricing of risk management contracts, without an objectively justifiable reason.

12.8. As part of this, the NDOs seek to ensure that another retailer that is as efficient as a gentailer's own retail business is not prevented from operating profitably in the electricity retail market.

12.9. The Authority proposes that each gentailer must regularly undertake a RPCA to demonstrate how the expected costs of electricity supply link to its retail pricing.

12.10. Other proposed principles are essential to support the first non-discrimination principle and ensure non-discriminatory treatment. The NDOs would require large gentailers to have internal policies and procedures to give effect to the non-discrimination obligations, keep records to demonstrate their compliance, self-report

[77] The proposals in this paper are part of a broader package of changes (not evaluated here) to improve the operation of the market for risk management products including strengthening trading of the super-peak standardised flexibility product and a review of market making.

breaches, provide an annual report on how they have met their obligations, and disclose certain relevant information.

12.11. The current Code requirement on gentailers to disclose ITPs would be repealed, given the post implementation review found it is not achieving its intended benefits, and as these would be made redundant by the disclosure requirements for the retail price consistency assessment.

12.12. A draft of the proposed Code amendment is contained in Appendix A.

The proposed amendment's benefits are expected to outweigh the costs

12.13. The Authority's preliminary view is that the proposal's benefits are expected to outweigh the costs. We are interested in stakeholders' views on this.

12.14. The Authority has attempted to quantify costs and benefits to the extent reasonably practicable. These are order-of-magnitude estimates only, given acknowledged information limits. While we recognise that quantification of costs and benefits is a useful element of good regulatory practice, ultimately the Authority is required to undertake a broad evaluative judgment in assessing whether to make a Code amendment.

The proposal is expected to generate benefits

12.15. The Authority identified a risk that one or more large gentailers may exercise significant market power to harm competing generators and retailers by:

- limiting access to risk management contracts (in particular super-peak hedges or firming contracts), or offering them at above workably competitive prices
- cross-subsidising their own retail arm or keeping retail prices below an 'as efficient' rival's costs.

12.16. The proposed NDOs are intended to mitigate these risks by seeking to reduce the risk of any:

- withholding of access to shaped hedges and other risk management contracts[78] by gentailers, including through increased monitoring of disclosed reasons for no offers or non-conforming offers
- discrimination in the pricing of hedges, including because the RPCA seeks to make transparent any differences between ASX or OTC hedge prices (of relevant durations) and the cost of supply a gentailer uses in setting retail prices
- anti-competitive retail margin squeezing by one or more gentailer, including because the RPCA requires them to show their retail prices are consistent with expected costs of supply.

[78] The proposal extends across risk management contracts. While the key risk identified to date relates to super-peak hedges, the proposal seeks to ensure a level-playing field in access and pricing and, in so doing ensure that discrimination risks are not simply moved to other types of risk management contracts because regulatory obligations apply to a specific product only.

12.17. Accordingly, by addressing the risk that gentailers may be exercising significant market power, the Authority considers that the potential benefits of the proposed NDOs would be:

- lower hedging costs for pass-through to retail consumers, by promoting access to risk management products (and, in particular, super-peak hedges) at competitive prices and so that buyers can avoid more costly risk management strategies
- downward pressure on retail prices, by providing a basis for greater confidence that participants are operating on a level playing field, in turn promoting competition by encouraging entry and expansion by independent retailers and generators.

12.18. These long-term and ongoing benefits may be offset by the near-term risk that a gentailer may need to raise its retail prices to comply with the NDOs if these are currently below levels of an ‘as efficient’ rival (buying hedges at prices largely set by gentailers).[79]

12.19. However, the Authority considers that, if unaddressed, any such anticompetitively low or below ‘as efficient’ rivals’ cost retail pricing would have the effect of undermining retail competition and result in higher long-run prices, to the long-term detriment of consumers.

12.20. The Authority notes that the NDOs seek to address a *risk* of a material exercise of market power, and that the RMR found it is likely that access and prices of risk management products reflect demand and supply conditions.

12.21. Realisation of benefits from the proposal do not rely on there being *actual* exercise of market power by one or more gentailers. The Authority considers that increased transparency and monitoring of OTC transactions and of retail margins will promote competition by providing independent generators and retailers confidence to enter or expand through assurance of a level playing field.

12.22. The proposal is also intended to mitigate the risk that the potential for exercise of market power rises in future, given rising demand for flexible generation that is owned by just a few gentailers if there are no alternatives forthcoming in sufficient quantities. We have discussed future developments and risks more extensively in the problem definition.

12.23. We consider that these forward-looking benefits outweigh the relatively modest implementation and compliance costs (as set out below).

12.24. The Authority is alive to the risk that, under a scenario where prices may currently be consistent with workable competition, the RPCA may cause gentailers to act conservatively to comply and pass-through energy costs faster than they otherwise would. This may not be for the long-term benefit of consumers. Competition among retailers ought to limit this risk, but the Authority will also seek to mitigate this through the guidance for the RPCA, including by acknowledging that there may be good reasons for a slim or negative margin in the near term, but that a persistent pattern or

[79] Noting that some gentailers have strongly submitted that they are not engaging in any margin squeeze – refer to the Contact submission.

the absence of a justifiable link between costs and retail prices would be a cause of concern.

12.25. The proposed NDOs may only partially address the risk of the sustained exercise of market power by one or more gentailers offering hedges at above competitive prices. This is because imperfect information makes it difficult to detect such behaviour. Monitoring of prices of OTC transactions will assist, but the Authority is looking to also address this through its broader package of hedge market improvements – including the upcoming review of market making.

Estimates of costs

12.26. The proposal's direct costs relate to gentailers' compliance and reporting obligations and the Authority's monitoring and enforcement functions. Table 3 sets out our current estimates of the annual costs, including set up costs in year 1. See Appendix F for assumptions underpinning these estimates.

Table 3: Estimates of implementation, administration and compliance costs

	Year 1	Year 2 onward	Notes
EA	$2.2m	$1.45m	Design retail price consistency assessment, ongoing policy function Develop & run OTC monitoring processes Investigations and enforcement
Gentailers	$2.2m	$0.88m	Design RPCA guidance Internal policies and training Keeping records, disclosures, reporting Participate in breach investigations
Total	$4.36m (+/- $1m)	$2.33m (+/- 0.5m)	Annual costs

Note: See Appendix G for details on how these numbers were derived.

12.27. The estimates of gentailers' costs cover implementation and ongoing administration cost. The proposal relies to a great extent on information that is already being disclosed, or on information the Authority expects gentailers to have. The Authority does not expect any of this to involve new 'infrastructure' though acknowledges there will be some process development costs. The proposed repeal of the ITP provisions in the Code will offset the additional costs somewhat.

12.28. The estimates of Authority costs cover additional monitoring and reporting activity, based on experience with trading conduct monitoring, as well as an allowance for additional capacity to undertake investigations and enforcement of suspected breaches.

12.29. At a discount rate of 8% (consistent with NZ Treasury guidance), the present value of the estimated costs of the proposal over 25 years is ~$27m ($21m-$32.6m).

12.30. If gentailers' costs turned out to be more than double our main estimate ($4.8m in year 1, and $2m ongoing), the present value total cost over 25 years would be ~40m.

12.31. The ongoing total costs of $2.3m per year (+/- $0.5m) is 0.02% of the $10.5b p.a. sales to residential, commercial and industrial consumers (incl. ~$3b for transmission and distribution).[80]

Quantifying benefits and break-even assessment

12.32. As set out above, the Authority considers that the proposal would put downward pressure on prices compared to a counterfactual where competition is reduced due to either foreclosure or lack of confidence in market settings that can stymie entry or expansion of retail and new generation by independent competitors.

12.33. Consumers paying less for electricity would result in transfers from producers to consumers. These may matter for consumers *now*, but they may not be in consumers' long-term interest if the proposal undermines producers' economic profits and incentives to supply and invest. As such, the Authority focuses on whether the proposal improves consumer surplus, net of any transfers. The conceptual approach is discussed in Appendix G.

12.34. Given the inherent difficulty of quantifying the extent to which the prices of risk management products or retail prices per kWh would reduce as a result of the proposal, the Authority has estimated by how much end prices per kWh faced by residential, commercial and industrial consumers would need to reduce for any gain in consumer surplus to at least offset the proposal's costs.

12.35. These order-of-magnitude results then provide a basis for the Authority to consider whether the price reductions needed to result in net benefits for consumers are plausible.

12.36. This limited approach still relies on making various simplifying assumptions (set out in Appendix G), including to estimate (indicative) consumer surplus measures. However, the Authority considers that an estimate of the order-of-magnitude impact on long run prices required to offset the estimated costs of the proposal to be a useful input to help inform deliberations alongside other factors it has set out.

12.37. Table 5 summarises the results. It presents results for three scenarios. The table also shows the potential impacts assuming the proposal is for the benefit of all electricity consumers (residential, commercial and industrial), and the more limited case assuming the proposal would mainly benefit mass market consumers.

12.38. Table 4 sets out key assumptions for our main or 'central' scenario and two alternative scenarios where we assumed alternative values for costs, price elasticities

80 This comparison of the potential costs of the proposal to data derived from published MBIE electricity statistics on total industry volumes and prices (rather than say revenues from gentailers) are because the costs as well as benefits may be faced by consumers eventually, and the majority of those revenues relate to gentailers. Annual reports for FY25 indicate gentailers revenues from electricity wholesale and retail were near $12b – noting differences will in part be explained by data presentation for accounting vs statistical uses.

and demand growth rates. The basis for these assumptions is discussed in Appendix G.

Table 4: Alternative assumptions to test sensitivity of results

Scenarios	Main	Low	High
Year 1 costs $m	4.4	3.4	5.4
Cost (ongoing) $m pa	2.3	1.8	2.8
Price elasticity	-0.45	-0.7	-0.2
Demand growth pa	1.7%	2.2%	1.1%

12.39. Adopting these assumptions, and data as at March 2025 for volumes and average c/kWh rates for different end-user groups (also presented in the appendix), the Authority estimated by how much these average rates would have to reduce for the proposal to break even, in terms of a zero net present value of consumer surplus.

Table 5: Summary results of breakeven analysis

	All consumers			Mass market only		
Scenarios	**Main**	**Low**	**High**	**Main**	**Low**	**High**
Present value of costs	26.8	21.0	32.6	26.8	21.0	32.6
Change in c/kWh needed	-0.86	-0.59	-1.46	-1.59	-1.10	-2.71
% Change in price needed	-3.1	-2.2	-5.3	-4.6	-3.2	-7.8
Change in quantity GWH	538	578	408	290	312	220
NPV Consumer surplus	0	0	0	0	0	0

Source: EA calculations.

12.40. The Authority estimates that breakeven (in terms of a zero net present value of consumer surplus) would require the proposal having the effect of reducing end users' prices, compared to the counterfactual, by:

- around 0.86 c/kWh (3.1%) for consumer surplus gains to offset the costs, if the proposal is assessed for its impact on all electricity consumers
- around 1.59 c/kWh (4.6%) for consumer surplus gains to offset the costs, if the proposal is assessed for its impact on retail customers only.

12.41. This change in c/kWh prices would be a permanent shift in the level of long run prices, compared to the counterfactual. It is assumed to occur in steps over the first three years.

12.42. The Authority currently considers these order-of-magnitude costs and benefits are plausible, and it appears likely that the proposal may generate quantified tangible benefits that exceed the costs.

12.43. The Authority also considers that, regardless, the costs of the proposal are modest in the context of the total market. They present a prudent investment in promoting confidence among independent retailers and generators and competition in the market, for the long-term benefit of consumers.

Risks and key caveats

12.44. The Authority acknowledges the near-term risk that, if one or more gentailer have been cross-subsidising their retail business or otherwise setting its retail prices below cost, then they will be under pressure to raise their retail prices to be in compliance with the NDOs. Such an increase would diminish the assessed benefits from the proposal initially, but to the extent that it reflected a practice of anticompetitively low pricing, the effect of the response would be to promote competition, which will bring benefits over time.

12.45. However, the Authority's high-level assessment did not find definitive evidence of margin squeezing through retail prices being set too low for 2018-2023.

12.46. Another risk for retail prices is that the RPCA creates pressure on gentailers to raise retail prices, for example, if the methodology were perceived to only be accommodating short duration contracts as a benchmark for the cost of supply, or if gentailers were to act conservatively to comply with the NDOs.

12.47. The Authority does not intend the RPCA to only be based on short duration contracts and will seek to mitigate the risk through RPCA guidance material as discussed above. This guidance should also reduce the risk of gentailers acting overly conservative to comply, as should competition among retailers.

12.48. The probability and impact of the risk of any near-term price increases are unknown. An increase in the retail price in year one would mean that the proposal's beneficial impact on competition and prices over time needs to be greater than indicated in our modelling. But that additional effectiveness to offset the any near-term price increase may not need to be large, because beneficial impacts of the proposal would persist over many years.

The Authority has considered other means for addressing the objectives

12.49. The Authority has identified and considered a range of options to address the objectives.

12.50. The LPF Options paper proposed and evaluated four main options:

- accounting separation of gentailers' generation and retail businesses
- principles-based NDOs (based on constructing an as-if internally traded portfolio of hedges) with escalation steps
- negotiate-arbitrate regulation
- corporate separation.

12.51. Submissions on these options and the Authority's further considerations are set out in Chapter 4.

12.52. The Authority also considered alternative options raised in submissions. These are also identified in Chapter 4. Some of these alternative options, such as developing the standardised super-peak product, market making, and developing demand response are being progressed as separate workstreams.

12.53. Given this context and submissions on the LPF Options paper, the options considered further are:

- No change – there is risk that the playing field is not level, but at this stage there is value in keeping a watching brief (increased monitoring) and keeping options open.
- Implement NDOs as initially proposed – gentailers may not discriminate on access or price against independent competitors and must construct economically meaningful internal hedge portfolios as a price benchmark.
- Implement NDOs with a RPCA – gentailers may not discriminate on access or price against independent competitors and must justify the link between expected supply costs and retail prices to show they are not cross-subsidising their retail arm or setting retail prices too low to harm competition.
- Mandate the voluntary Code of Conduct for OTC participants – the code is an industry working group's 'consensus on behaviours and conduct consistent with an efficient and competitive OTC market'.
- Corporate separation – legal independence between the generation and retail arms plus arm's length rules to provide strong safeguards against a gentailer favouring its internal business units in access and pricing hedges.

12.54. We use the 'no change' option as the counterfactual against which we assess the other options. However, as our assessment shows, we consider that doing nothing is not a credible option. It would not be effective in promoting competition by providing greater confidence among current and potential independent retailers and generators that the playing field is level.

12.55. As discussed in Chapters 4 and 8, other options have been considered but not taken forward as they are:

- unlikely to be sufficiently effective or workable (such as negotiate-arbitrate); or
- currently appear disproportionate to the risk as well as likely to take a long time, be costly, and with high legal risks that further raise costs (such as structural separation).

The proposed amendment is preferred to other options

12.56. The Authority has evaluated the other means for addressing the objectives and prefers the proposal.

Assessment criteria

12.57. In the LPF Options paper, the Authority proposed eight assessment criteria: six on effectiveness and risk (transparency, hedge market liquidity, investment and innovation, retail market competition, wholesale market competition, investment and innovation, other efficiencies), cost and timing, and workability.

12.58. Some submissions agreed these provided an appropriate framework (e.g. EEA, Lodestone, Octopus, SEANZ), though these and others also suggested there needed to be a greater emphasis on various aspects, such as:

- the impact on consumers and consumer confidence (EEA, IER)
- effectiveness in addressing the problem (EEA, Octopus, Pulse)
- risks of sudden near-term retail price impacts and affordability (Contact, Meridian), and other unintended consequences (Pulse, Energy Link)
- proportionality (Houston Kemp as part of the Mercury panel, Pulse)
- timeliness (NZ Steel, Octopus)
- enforceability (Helios, Octopus).

12.59. The Authority agrees these are useful considerations in assessing the advantages and disadvantages of the options and our assessment of whether, and the extent to which, each of they will promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

12.60. To keep the number of criteria and analysis manageable, Table 6 consolidates the earlier assessment criteria with suggestions from submitters.

Table 6: Assessment criteria

Criteria	The Authority favours proposals that …
Effective	promote competition for the long-term benefit of consumers by - addressing the targeted access and pricing risks and market confidence problems[81] - promoting competitive conduct and identifying potentially anticompetitive conduct for further action
Cost	keep initial implementation and ongoing administrative and compliance costs proportional to the risks and issues being addressed
Timely	are capable of creating desired impacts in the near term
Workability	are implementable and enforceable
Risk	manage risks that come with change, including from unintended consequences, for example by favouring reversible or adaptable solutions avoid creating disincentives to innovate and invest

[81] The February proposal broke out “effective” across a range of outcomes - hedge market liquidity, investment and innovation, retail market competition, wholesale market competition, investment in new flexibility. While those lenses remain valid, we are conscious that this is a targeted proposal, seeking to address a specific discrimination risk in the hedge market.

Table 7: Qualitative assessment of alternative means for addressing the objectives

Options:	Effective	Cost	Timely	Workability	Risks	Overall
NDOs with internal portfolio	Transparency promotes competition in retail and generation via better access and confidence in level playing field	Relatively modest compliance + monitoring cost Lost efficiencies if gentailers have less flex over own capacity	Principles and disclosures relatively quick to implement	Delays possible while conceptual and practical issues with pricing implicit internal hedge portfolios are resolved	Risk of retail price correction if gentailers are cross-subsiding or pricing below cost now Info limits may hinder issue identification	
NDOs with RPCA	Transparency promotes competition in retail and generation via better access and confidence in level playing field	Relatively modest compliance + monitoring cost, and likely lower than constructing internal portfolios. Lost efficiencies if gentailers have less flex over own capacity	Principles, disclosures, and RPCA designed and implemented relatively quickly (and more quickly than internal portfolio)	Reliance on existing market information and gentailer information Guidance for robust, comparable measures	Risk of retail price correction if gentailers are pricing below cost now, or react overly conservatively Info limits may hinder issue identification	
Mandate voluntary code for OTC participants	Would not sufficiently promote confidence in LPF- does not clearly prohibit discrimination, and does not provide transparency	Limited if any additional cost	Existing solution, already being applied by signatories to the code	Existing solution, but is not supported by record keeping and disclosure requirements to support monitoring or investigation	Likely insufficient as a response to risk and could damage confidence that there is a level playing field	
Corporate separation	High transparency promotes competition via confidence in LPF, but offset by loss of vertical integration efficiencies	Significant costs associated with separation process	Will take significant time to design and implement	Would likely require primary legislation. Challenges in identifying breaches in arm's length rules	Unintentionally may send negative signals about NZ investment environment.	

Key:	**Very positive**	**Positive**	**Neutral**	**Negative**	**Very negative**

12.61. The Authority currently considers that the benefits are likely to exceed the costs of the proposal, and that the proposal is likely superior to the status quo and to the alternative options that have been assessed.

12.62. In developing this proposal, the Authority has had regard to the Government Policy Statement of 2024 (GPS) in accordance with s17 of our Act. In particular, this proposal aims to reduce the risk of the exercise of market power and promote effective competition including in the markets for electricity retail services.

The proposed amendment complies with section 32(1) of the Act

12.63. The Authority's main objective under section 15(1) of the Act is to promote competition in, reliable supply by, and efficient operation of, the electricity industry for the long-term benefit of consumers. The Authority's additional objective under section 15(2) of the Act is to protect the interests of domestic and small business consumers in relation to their supply of electricity. The additional objective only applies to the Authority's activities in relation to the direct dealings between participants and these consumers.

12.64. Section 32(1) of the Act says that the Code may contain any provisions that are consistent with the Authority's objectives and are necessary or desirable to promote any or all of the matters listed in section 32(1) (which includes competition in and the efficient operation of the electricity industry).

12.65. The Authority considers that the proposed amendment is necessary or desirable to promote competition in, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

The Authority has given regard to the Code amendment principles

12.66. In developing and considering the proposed amendments to the Code, the Authority has had regard to the Code amendment principles as set out in the Consultation Charter.[82]

12.67. Table 8 (below) describes how the Authority had regard to these principles in the preparation of the proposal.

Table 8: Summary of the assessment against Code amendment principles

Principle	
1. Clear case for regulation	The Authority has identified a clear case for amending the Code, as set out in this document and the regulatory statement.

[82] Electricity Authority, "Consultation Charter," 27 February 2024, https://www.ea.govt.nz/documents/482/Consultation_Charter_2024.pdf.

2. Costs and benefits are summarised	The Authority has undertaken an evaluation of the costs and benefits of the proposed amendment and has included this in the regulatory statement. The Authority considers that the expected benefits exceed the estimate of costs of the proposal.
The following additional principles are considered where analysis demonstrates a clear benefit to a Code amendment proposal, but there is no clear best option in terms of a solution. As the Authority considers there is a clear best option for consultation, the Authority did not further consider these additional principles in greater detail.	
3. Preference for small-scale 'trial and error' options	
4. Preference for greater competition	
5. Preference for market solutions	
6. Preference for flexibility to allow innovation	
7. Preference for non-prescriptive options	

Questions

Q25. Do you agree with the objectives of the proposed amendment? If not, why not?

Q26. Do you agree the benefits of the proposed amendment outweigh its costs?

Q27. Do you agree the proposed amendment is preferable to the other options? If you disagree, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.

Q28. Do you agree the Authority's proposed amendment complies with section 32(1) of the Act?

Q29. Do you have any comments on the regulatory statement?

Appendix A Proposed Code amendments

A.1. This appendix sets out the proposed Code amendments, including:

A.2. draft amendments to introduce the NDOs; and

A.3. draft amendments to the ITP/RGM provisions.

Electricity Industry Participation Code 2010
Part 1
Preliminary provisions

…

A.4. Interpretation

(1) In this Code, unless the context otherwise requires,—

…

buyer, for the purposes of subpart 5, subpart 5C, and subpart 7 of Part 13, means—

(a) in respect of a **contract for differences**, the fixed-price payer, being the **party** obliged to make payments at a fixed price from time to time during the **term** of the contract; or

(b) in respect of a **fixed-price physical supply contract**, the purchaser of **electricity**; or

(c) in respect of an **options contract**, either—

(i) the **party** paying the **premium**; or

(ii) if there is no **premium**, the **party** who agrees to be the **buyer** for the purposes of subpart 5 or subpart 7 (as applicable) of Part 13; or

(iii) if neither **party** agrees to be the **buyer**, the **party** whose name is the first alphabetically; or

(ca) for the purposes of subpart 5 of Part 13, in respect of a contract prescribed by the **Authority** under clause 13.219B as a **risk management contract**, either—

(i) the **party** specified as the buyer in the contract; or

(ii) if neither **party** is specified as the buyer, the **party** whose name is the first alphabetically; or

(cb) for the purposes of subpart 5C of Part 13, in respect of a contract prescribed by the **Authority** under clause 13.219B as a **risk management contract,** the **party** specified as the buyer in the contract; and

(d) for the purposes of subpart 7 of Part 13, in respect of any other contract, the **party** consuming the **electricity** that the contract relates to;

(e) for the purposes of subpart 5C of Part 13, a **buyer**—

(i) includes a person that has indicated to a **gentailer** a desire to obtain **risk management contracts** from a **gentailer**; and

(ii) does not include a **gentailer's** own **internal business units**

buyer confidential information, for the purposes of subpart 5C of Part 13, means:

(a) information that—

(i) a **buyer** provides to a **gentailer** in relation to the provision of **risk management contracts**; or

(ii) a **gentailer** otherwise holds or obtains in relation to the provision of **risk management contracts** to a **buyer**; and

(b) information that:

(i) is by its nature confidential or proprietary to the **buyer**; or

(ii) is disclosed in confidence by the **buyer**; or

(iii) a **gentailer** knows or ought reasonably to know is confidential to the **buyer**; or

(iv) concerns a person that is, or intends to become, a customer of the **buyer**; but

(c) does not include:

(i) information that was publicly available at the time of receipt, or that becomes publicly available other than as a result of a breach of confidentiality; or

(ii) information that was obtained bona fide by a **gentailer** from another person who is in lawful possession of the information and who did not acquire the information directly or indirectly from the **buyer** under an obligation of confidence; or

(iii) information, or types of information, that a **buyer** agrees with the **gentailer** is not **buyer confidential information**

…

commercial information, for the purposes of subpart 5C of Part 13, means information that is—

(a) held by a **gentailer**; and

(b) relates to the supply by that **gentailer** of **risk management contracts**, including the **gentailer's**:

(i) current capacity to supply **risk management contracts**; and

(ii) future capacity to supply **risk management contracts**; but

(c) does not include:

(i) any information that is:

(A) has been superseded by identifiable new information;

(B) is more than 18 months old; or

(C) is otherwise not current; or

(ii) any information, or types of information, that the **gentailer** and the **Authority** agree in writing is not commercial information

…

~~**generator retailer** means a **trader** who is both a **generator** and a **retailer** and in any month of the **financial year** of the **generator retailer**:~~

~~(a) has sold to the **clearing manager** an amount of **electricity** at least equivalent to 5% of the total amount of **electricity** sold in any of those months by all **generators** who are **traders** to the **clearing manager**, as measured in **MWh**; and~~

~~(b) was recorded in the **registry** in any of those months as being responsible for at least 5% of the total number of **ICPs** registered in the registry with an **ICP** status of "Active",~~

~~and, for the purposes of this definition, the terms "**trader**", "**generator**" and "**retailer**" include any related company, as defined in section 2 of the Companies Act 1993, of a~~

~~**participant** provided that the related company is a **participant**~~

gentailer means—
(a) Contact Energy Limited;
(b) Genesis Energy Limited;
(c) Mercury NZ Limited;
(d) Meridian Energy Limited

…

interconnected bodies corporate has the meaning given to it in section 2(7) of the Commerce Act 1986

…

internal business units means the separate functions of a **gentailer's** business (including, for example, generation, retail and other business units), even where these functions are not clearly separated in the **gentailer's** organisational structure, and includes functions undertaken by any interconnected bodies corporate of the **gentailer**

…

~~**ITP information** means information on internal transfer pricing as described in clause 13.256~~

…

mass market customers means all those customers of a ~~**generator retailer** or~~ **retailer** who the ~~**generator retailer** or~~ **retailer** classifies as mass market or who are commonly understood to be **mass market customers** in accordance with standard industry practice

…

non-discrimination policy has the meaning given to it in clause 13.236Q

non-discrimination principles means the non-discrimination principles in clause 13.236P

…

~~**retail ITP** means the notional price or prices per **MWh** for **electricity** set between either the generating arm or the trading arm of a **generator retailer**, on the one hand, and the retailing arm of the **generator retailer**, on the other hand, in respect of **electricity** generated by the **generator retailer** that is sold by the **generator retailer** to **mass market customers** and that is used for internal accounting, management, or other purposes~~

retailer, means as follows:

(a) except as provided in paragraphs (b) and (c), a participant who supplies electricity to another person for any purpose other than for resupply by the other person:

(b) in Parts 1 (except for the definition of specified participant), 8, 10, and 12 to 15, a participant who supplies electricity to a consumer or to another retailer:

(c) in subpart 4 of Part 9, the retailer defined in paragraph (a) who is recorded in the registry as being responsible for the ICP described in clause 9.21(1)(b):

(d) for the purposes of clauses 13.259-13.266 only, does not include a gentailer

...

retail price consistency assessment means an assessment of the difference between a **gentailer's** expected cost of electricity supply and that **gentailer's** retail prices

…

risk management contract, for the purposes of subpart 5, subpart 5C, and subpart 7 of Part 13, means—

(a) a **contract for differences**; or

(b) a **fixed-price physical supply contract**; or

(c) an **options contract**; or

(ca) for the purposes of subpart 5 and subpart 5C of Part 13, a contract prescribed by the Authority under clause 13.219B as a risk management contract; but

(d) does not include an **FTR**

...

uncommitted capacity means a **gentailer's** reasonable expectation of its ability to offer **risk management contracts** in future periods, calculated as a **gentailer's** expected gross forecast ability to offer **risk management contracts**, less:

(a) the amount of generation that could otherwise be used to back **risk management contracts** that the **gentailer** reasonably expects to use to supply electricity to its end customers; and

(b) a **gentailer's** wholesale commitments, comprised of **gentailer** market making commitments (regulated or voluntary) and existing **risk management contracts** entered into with **buyers**

…

Electricity Industry Participation Code 2010
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Trading arrangements

…

Subpart 5C—Non-Discrimination Obligations

13.236O Purpose of this subpart
The purpose of this subpart is to promote competition in, and the efficient operation of, the electricity industry for the long-term benefit of consumers by requiring **gentailers** to supply **risk management contracts** to **buyers** on a non-discriminatory basis to—

(a) ensure even-handed supply of **risk management contracts;**
(b) support the liquidity and competitive pricing of **risk management contracts**; and
(c) facilitate investment in the electricity industry.

Non-discrimination principles

13.236P Non-discrimination principles
The non-discrimination principles are as follows:

Non-discrimination principle 1
Non-discriminatory supply

(1) A **gentailer** must not discriminate between **buyers** for the supply of **risk management contracts** without an objectively justifiable reason.
(2) A **gentailer** must not discriminate against **buyers** in favour of its own **internal business units** for the supply of **uncommitted capacity** without an objectively justifiable reason.
(3) A **gentailer** must not discriminate against **buyers** in favour of its own **internal business units** when pricing **risk management contracts** without an objectively justifiable reason.
(4) For the avoidance of doubt, subclause (3) requires pricing of **risk management contracts** in such a way as to ensure that any **buyer** that supplies **electricity** to end users at retail, that is as efficient with regard to operating costs as the **gentailer's** own retail **internal business unit**, and adopts a reasonable risk management approach, is not prevented from operating profitably.

Non-discrimination principle 2
Obligation to trade in good faith

(5) A **gentailer** must engage with **buyers** in good faith and in a timely and constructive manner in relation to the supply of **risk management contracts**.

Non-discrimination principle 3
Objective credit assessments

(6) A **gentailer's** credit terms and collateral arrangements relating to the supply of **risk management contracts** to **buyers** must reflect a reasonable, consistent and transparent assessment of the risk of trading with a **buyer**.

Non-discrimination principle 4

Equal access to commercial information

(7) A **gentailer** must ensure that any **commercial information** relating to **risk management contracts** made available to its **internal business units** that compete with **buyers** is also made available to **buyers** at the same time.

Non-discrimination principle 5

Protection of confidential information

(8) A **gentailer** must protect **buyer confidential information** and establish robust processes to prevent disclosure of **buyer confidential information** to, and use of **buyer confidential information** by, any of the **gentailer's internal business units** that may compete with the **buyer**.

Non-discrimination principle 6

Record keeping

(9) A **gentailer** must establish, maintain and keep records that demonstrate its compliance with these **non-discrimination principles**."

Non-discrimination policy and implementation plan

13.236Q Non-discrimination policy

(1) A **gentailer** must at all times maintain an internal policy ("**non-discrimination policy**") that details operational practices in place to ensure the **gentailer's** trading of **risk management contracts** occurs in accordance with the **non-discrimination principles**.

(2) The **non-discrimination policy** referred to in subclause (1) must be reviewed and approved by the **gentailer's** board at least once a year.

(3) Each time the **gentailer** amends its **non-discrimination policy**, the **gentailer** must disclose a copy of the amended **non-discrimination policy** to the **Authority** within 10 working days of the amended policy taking effect.

13.236R Implementation plan

(1) A **gentailer** must prepare an implementation plan detailing its approach to complying with the **non-discrimination principles**.

(2) A **gentailer's** implementation plan is to be provided to the **Authority** and published on the **gentailer's** website on 1 July 2026.

(3) The implementation plan must include (without limitation) the **gentailer's**:

  (a) **non-discrimination policy**;

  (b) planning (including any steps already taken) for training its employees, directors and agents on compliance with the **non-discrimination principles**;

  (c) planning (including any steps already taken) for ensuring ongoing compliance with the **non-discrimination principles** (for example, through regular internal audits).

Record-keeping and disclosure requirements

13.236S Record-keeping

(1) A **gentailer** is required to establish, maintain and keep comprehensive records that demonstrate how it meets the **non-discrimination principles**.

(2) Without limiting subsection (1), a **gentailer** must establish, maintain and keep records of:

(a) the total capacity of the **gentailer** to offer **risk management contracts**, and their **uncommitted capacity**, over the next 3 years;

(b) the **gentailer's** monthly **electricity** supplied over the past 12 months

(c) the **gentailer's** expected monthly **electricity** supply over the next 3 years;

(d) the **gentailer's** methodologies for pricing of **risk management contracts**;

(e) any reason for discriminating between **buyers**, or against **buyers** in favour of a **gentailer's** own **internal business units**, for the purposes of non-discrimination principle 1 of the **non-discrimination principles** (set out in clause 13.236P(1)-(3));

(f) all complaints received by the **gentailer** by any person about any conduct of the **gentailer** that the person believes might constitute a breach of this subpart.

13.236T Annual reporting

(1) Within 45 working days after the end of each **gentailer financial year** (including the first **gentailer financial year** (or part thereof) following this subpart coming into force), a **gentailer** must provide an annual report to the Authority, that demonstrates whether and how that **gentailer** has met the **non-discrimination principles** in that **financial year**.

(2) Without limiting subsection (1), the annual report must include:

(a) the matters set out in clause 13.236S(2); and

(b) a **retail price consistency assessment** in accordance with clause 13.236V.

(3) When providing the annual report to the **Authority**, a **gentailer** must certify that the **gentailer** has complied with the **non-discrimination principles** during the relevant **gentailer financial year** (except for any breaches that have been reported, or are reported with the certificate, to the **Authority** in accordance with clause 13.236X).

(4) The certification referred to in subclause (3) must be:

(a) signed by at least two directors of the gentailer;

(b) accompanied by a statement confirming the truth and accuracy of the certification to the best of those directors' knowledge and belief having made all reasonable enquiries (including an explanation of the enquiries made).

13.236U Interim report

(1) Within 20 working days after the end of the first six-month period following this subpart coming into force, a gentailer must provide an interim report to the **Authority** that demonstrates whether and how the **gentailer** has met the **non-discrimination principles** during that six-month period.

(2) Without limiting subsection (1), the interim report must include:

(a) the matters set out in clause 13.236S(2); and

(b) a **retail price consistency assessment** in accordance with clause 13.236V.

13.236V Retail price consistency assessments

(1) A **gentailer** must undertake a **retail price consistency assessment**:

(a) for each of its retail brands within each retail segment; and
(b) on the coming into force of this subpart and every six months thereafter (following the end of the first and second half of the **gentailer's financial year**).

(2) A **gentailer's retail price consistency assessment** must be provided to the **Authority**—
(a) by 1 July 2026, in respect of the initial **retail price consistency assessment** referred to in subclause (1)(a);
(b) together with the interim report referred to in clause 13.236U(1), in respect of a **retail price consistency assessment** undertaken at the end of the first six-month period following this subpart coming into force (as required by clause 13.236U(2));
(c) together with the annual report referred to in clause 13.236T(1), in respect of a **retail price consistency assessment** undertaken for the second half of the **gentailer's financial year** (as required by clause 13.236T(2)(g));
(d) otherwise, within 20 working days after the end of the relevant half of the **gentailer's financial year**.

(4) The Authority must publish guidance on the recommended methodology for undertaking **retail price consistency assessments**.

(5) Each time a **gentailer** provides a **retail price consistency assessment** to the **Authority**, it must include a clear and full explanation of its approach, including (without limitation):
(a) areas in which, and reasons why, it has departed from the methodology published by the **Authority** referred to in subclause (4); and
(b) the underlying data on retail prices and wholesale costs.

13.236W Public reporting

(1) A **gentailer** must prepare and publish public versions of the annual report referred to in clause 13.236T(1), the interim report referred to in clause 13.236U(1) or any **retail price consistency assessment** prepared in accordance with clause 13.236V (including the explanation referred to in clause 13.236V(5)) on the **gentailer's** website within 5 working days of providing of the relevant report or **retail price consistency assessment** to the **Authority**.

(2) When preparing a public version of an annual report, interim report or **retail price consistency assessment**, a **gentailer** may redact information that it reasonably considers is commercially sensitive or otherwise confidential, but any such redactions should be kept to a minimum to promote transparency.

(3) The public version of any annual report, interim report or **retail price consistency assessment** must be:
(a) provided to the **Authority** at the same time as submitting the relevant annual report, interim report or **retail price consistency assessment**; and
(b) accompanied by an explanation of the basis for any redactions made under subclause (2).

13.236X Self-reporting of breaches

(1) If a **gentailer** believes, on reasonable grounds, that it may have breached this subpart, the **gentailer** must report the alleged breach to the **Authority** as soon as reasonably practicable, and no later than 20 working days after the **gentailer** becomes aware of the alleged breach.

(2) Any report under subsection (1) must be in writing and must specify:
(a) the relevant provision of this subpart allegedly breached; and

(b) the circumstances relating to the alleged breach; and
(c) the extent and impact of the alleged breach, including any affected **parties** or processes; and
(d) any remedial actions taken or proposed; and
(e) the date and time the alleged breach occurred.

…

~~*Provision of internal transfer pricing information by generator retailers*~~

~~**13.256 Generator retailers must provide ITP information to the Authority**~~

~~(1) Each **generator retailer** must provide the **ITP information** in relation to the **generator retailer** to the **Authority** in the form and by the means specified by the **Authority** no later than 90 days after the end of the **financial year** of the **generator retailer**.~~

~~(2) The **ITP information** must consist of the following information in relation to the **generator retailer's financial year**:~~

~~(a) the average load weighted **retail ITP**, calculated by dividing the total notional cost of **electricity** under the **retail ITP** arrangements of the **generator retailer** by the total amount of **electricity** in **MWh** sold by the **generator retailer** to **mass market customers**:~~

~~(b) information on how the **generator retailer** determined the **retail ITP**, at a sufficient level of detail to enable a reasonable person, being a person who has a reasonably sophisticated understanding of the operation of the **electricity** industry and the **wholesale market**, to determine how the **generator retailer** determined the **retail ITP**.~~

~~(3) The information provided by a **generator retailer** under subclause (2)(b) must include the following:~~

~~(a) a breakdown of the key components or factors which make up the **retail ITP** expressed as an amount in dollars and cents per **MWh** that each key component or factor comprises of the average load weighted **retail ITP** required by subclause (2)(a), and which must include (if relevant) the following components or factors:~~

~~(i) prices in **ASX NZ electricity futures**:~~

~~(ii) the distribution of the total electrical load across locations, including the adjustment, calculated on an average load weighted basis in **MWh**, that the **retailer** generator used to determine the **retail ITP** for the **electricity** sold to **mass market customers** beyond a **node** specified in an **ASX NZ electricity future**:~~

~~(iii) administrative fees, including management fees, notionally charged by the **generator retailer** to the **generator retailer's** retail arm:~~

~~(iv) the level of discretionary judgement the **generator retailer** exercised to amend or otherwise modify the draft **retail ITP** before it was finalised:~~

~~(v) all other key components or factors the **generator retailer** relied on to determine the **retail ITP**, and any other material information used by the **generator retailer** to determine the **retail ITP** that is not publicly available:~~

~~(b) any residual components or factors that make up the **retail ITP**, but which are~~

~~not components or factors required by paragraph (a), expressed as one combined amount in dollars and cents per **MWh**:~~

~~(c) an explanation of the methodology the **generator retailer** used to determine or to assist in determining the **retail ITP**, and which must include (if relevant) the following:~~

- ~~(i) the assumed process used by the **generator retailer** to build the hedge book of **ASX NZ electricity futures**, including the following:~~
  - ~~(A) the proportion of **ASX NZ electricity futures** the **generator retailer** assumed would be purchased and the assumed timing of those assumed purchases:~~
  - ~~(B) the relative weighting of **ASX NZ electricity futures** relating to Benmore as compared to those relating to Otahuhu:~~
  - ~~(C) the types of **ASX NZ electricity futures** the **generator retailer** assumed to be purchased and the maturities purchased:~~
  - ~~(D) the basis on which the **ASX NZ electricity futures** are priced:~~
- ~~(ii) the approach the **generator retailer** took to adjust for:~~
  - ~~(A) differences in the within day electrical load and cost profile underlying the **ASX NZ electricity futures** and the **generator retailer's mass market customers** load profile:~~
  - ~~(B) distribution of electrical load across locations, including the relative use of **FTRs** or historical price differences to price for load by location:~~
- ~~(iii) the approach or methodology used to determine the electrical load profile, including the following:~~
  - ~~(A) whether actual or assumed load profiles are relied upon:~~
  - ~~(B) the degree of granularity of load with respect to location, seasonality and intra-day:~~
  - ~~(C) the percentage of load by regional geographical location:~~
- ~~(iv) the basis for and determination of fees, including management or associated fees, the **generator retailer** notionally charged its retail arm:~~
- ~~(v) the basis for and rationale behind any discretion the **generator retailer** exercised:~~
- ~~(vi) any other details the **generator retailer** considers material to explain the methodology the **generator retailer** used to determine or assist in determining the **retail ITP**:~~

~~(d) the key non-price parameters the **generator retailer** used to determine the **retail ITP** including whether or not the **retail ITP** is:~~

- ~~(i) for fixed or variable volume of **electricity**; or~~
- ~~(ii) for a fixed or variable price of **electricity**:~~

~~(e) the purposes for which the **retail ITP** is used by the **generator retailer**, including whether the **retail ITP** is used as part of setting the price of **electricity** sold to **mass market customers** by the **generator retailer**:~~

~~(f) if relevant, and if not disclosed under paragraph (e), any matters relating to the **generator retailer** which the **retail ITP** directly or indirectly affects.~~

~~(4) Where a **generator retailer** and one or more other **generator retailers** are related companies, as defined in section 2 of the Companies Act 1993, and are required by subclause (1) to provide **ITP information** to the **Authority**, the obligation in subclause~~

~~(1) is met by one of those **generator retailers** providing the **ITP information** relating to all the **generator retailers** on a consolidated basis for the **generator retailers** to the **Authority**.~~

~~(5) If a **generator retailer** provides **ITP information** on behalf of other **generator retailers** under subclause (4), the **generator retailer** providing the **ITP information** must identify the other **generator retailers** as part of the **ITP information** provided.~~

~~13.257 Disclosure of change of methodology~~

~~(1) This clause applies if—~~

~~(a) a **generator retailer** changes the methodology used to determine the **retail ITP** for a **financial year** ("the current **financial year**") from the methodology used in a previous **financial year** for which the **generator retailer** provided **ITP information** under clause 13.256, other than where that change relates solely to the distribution of the customer load base or the input prices (**ASX NZ electricity futures** prices and locational prices as provided for in clause 13.256(3)(a)(i) and (ii)); and~~

~~(b) that change in methodology has the effect of modifying the **retail ITP** by an amount in excess of 5% from the **retail ITP** contained in the most recent **ITP information** the **generator retailer** provided under clause 13.256.~~

~~(2) Where this clause applies, the **generator retailer** must also provide the following information to the **Authority** in the form and by the means specified by the **Authority**:~~

~~(a) details of the impact on the average load weighted **retail ITP** disclosed under clause 13.256 for any of the previous three **financial years** if the new methodology had been used to determine the **generator retailer's retail ITP** for those previous **financial years**:~~

~~(b) details of the impact on the average load weighted **retail ITP** for the current **financial year** if the methodology used in any of those previous **financial years** was used to determine the **generator retailer's retail ITP** for the current **financial year**.~~

~~(3) The **generator** must provide the information required by subclause (2) to the **Authority** at the same time as providing the **ITP information** required under clause 13.256 for the current **financial year**.~~

~~(4) Where a **generator retailer** and one or more other **generator retailers** are related companies, as defined in section 2 of the Companies Act 1993, and are required by subclause (2) to provide information to the **Authority**, the obligations in subclause (2) are met by one of those **generator retailers** providing the information relating to all the **generator retailers** on a consolidated basis for all the **generator retailers** to the **Authority**.~~

~~(5) If a **participant** provides information on behalf of other **generator retailers** under subclause (4), the **generator retailer** providing the information must identify the other **generator retailers** as part of the information provided.~~

~~**13.258 Publication of ITP information by the Authority**~~

~~The **Authority** may publish any **ITP information** or information submitted to it under clause 13.257, as the **Authority** sees fit.~~

Provision of retail gross margin reports by retailers

13.259 Provision of retail gross margin report by retailers

(1) Each **retailer** must provide a **retail gross margin report** to the **Authority** no later than 90 days after the end of the **retailer's financial year**.

~~(2) Subclause (1) does not apply to any **retailer** who was recorded in the **registry** in any of the preceding 12 months as being responsible for less than 1% of the total number of **ICPs** registered in the **registry** with an **ICP** status of "Active".~~

(2) Subclause (1) does not apply to:

(a) any **retailer** who was recorded in the **registry** in any of the preceding 12 months as being responsible for less than 1% of the total number of **ICPs** registered in the **registry** with an **ICP** status of "Active"; or

(b) any **gentailer**.

(3) The **retail gross margin report** must consist of the following information relating to the sale of **electricity** to **mass market customers** for the **financial year** by the **retailer**:

(a) the total amount of **electricity** sold by the **retailer** to **mass market customers** expressed as **MWhs**:

(b) revenue derived from the sale of **electricity** to **mass market customers** expressed as an amount of dollars per **MWh**:

(c) cost of **electricity** sold by the **retailer** to **mass market customers**~~, including the cost of **electricity** derived from **retail ITP**,~~ expressed as an amount of dollars per **MWh**:

(d) cost of **metering** services associated with the sale of **electricity** to **mass market customers** expressed as an amount per **MWh**:

(e) cost of **distribution** services associated with the sale of **electricity** to **mass market customers** expressed as an amount per **MWh**:

(f) cost of transmission services, being those services provided by **Transpower** under a **transmission agreement**, paid by the **retailer** associated with the supply of **electricity** to **mass market customers** by the **retailer** expressed as an amount per **MWh**:

(g) cost of levies associated with the supply of **electricity** to **mass market customers** by the **retailer** expressed as an amount per **MWh**.

(4) A **retail gross margin report** must be prepared in accordance with generally accepted accounting practices and in the form specified by the **Authority**.

(5) Where a **retailer** and one or more other **retailers** are related companies, as defined in section 2 of the Companies Act 1993, and are required by subclause (1) to provide a **retail gross margin report** to the **Authority**—

(a) the obligation in subclause (1) is met by one of those **retailers** providing the **retail gross margin report** relating to all the **retailers** on a consolidated basis for all the **retailers** to the **Authority**; and

(b) in any such case, the **retailer** providing the information must identify the other

retailers, as part of the information provided.

13.260 Publication of information contained in retail gross margin reports by the Authority

The **Authority** may **publish** the information received in a **retail gross margin report**, except that information contained in a **retail gross margin report** submitted by a **retailer** with less than 5% of total market share by **ICP** with a status of "Active" must be anonymised so as not to identify that **retailer**.

Authority may require review of ~~ITP information and~~ retail gross margin reports

13.261 Authority may require review of ~~ITP information and~~ retail gross margin reports by independent person

~~The **Authority** may, in its discretion, require a review by an independent person of whether—~~

~~(a) a **generator retailer** may not have complied with one or both of clauses 13.256 or 13.257; and~~

~~(b) a **retailer** may not have complied with clause 13.259.~~

The **Authority** may, in its discretion, require a review by an independent person of whether a **retailer** may not have complied with clause 13.259.

13.262 Nomination of independent person to undertake review

(1) If the **Authority** requires a review under clause 13.261—

(a) the **Authority** must require the ~~**generator retailer** or~~ **retailer** to nominate an appropriate independent person to undertake the review; and

(b) the ~~**generator retailer** or~~ **retailer** must provide that nomination within a reasonable timeframe.

(2) The **Authority** may direct the ~~**generator retailer** or~~ **retailer** to appoint the person nominated under subclause (1) or to nominate another person for approval.

(3) If the ~~**generator retailer** or~~ **retailer** fails to nominate an appropriate person under subclause (1) within 5 **business days**, the **Authority** may direct the ~~**generator retailer** or~~ **retailer** to appoint a person of the **Authority's** choice.

(4) The ~~**generator retailer** or~~ **retailer** must appoint a person to undertake the review in accordance with a direction made under subclause (2) or subclause (3).

13.263 Factors relevant to a direction under clause 13.262

(1) In making the direction required by clause 13.262(2) or clause 13.262(3), the **Authority** may have regard to any factors it considers relevant in the circumstances, including the following:

(a) the degree of independence between the ~~**generator retailer** or~~ **retailer** and the person nominated under clause 13.262(1); and

(b) the expected quality of the review; and

(c) the expected costs of the review.

(2) For the purposes of subclause (1)(a), the **Authority** may have regard to the

special definition of independent under clause 1.4 but it is not bound by that definition.

13.264 Carrying out of review by independent person

(1) A ~~**generator retailer** or~~ **retailer** subject to a review under clause 13.261 must, on request from the person undertaking the review, provide that person with such information as the person reasonably requires in order to carry out the review.

(2) The ~~**generator retailer** or~~ **retailer** must provide the information no later than 10 **business days** after receiving a request from the person for the information.

(3) The ~~**generator retailer** or~~ **retailer** must ensure that the person undertaking the review—

(a) produces a report on whether, in the opinion of that person, the ~~**generator retailer** or~~ **retailer** may not have complied with clause~~s 13.256, 13.257 or~~ 13.259~~ (as specified by the **Authority** under clause 13.261)~~; and

(b) submits the report to the **Authority** within the timeframe specified by the **Authority**.

(4) The report produced under subclause (3)(a) must include any other information that the

Authority may reasonably require.

(5) Before the report is submitted to the **Authority**, any identified failure of the ~~**generator retailer** or~~ **retailer** to comply with clause~~s 13.256, 13.257 or~~ 13.259 must be referred back to the ~~**generator retailer** or~~ **retailer** for comment.

(6) The comments of the ~~**generator retailer** or~~ **retailer** must be included in the report.

13.265 Payment of review costs

(1) If a report received under clause 13.264(3)(a) establishes, to the **Authority's** reasonable satisfaction, that the ~~**generator retailer** or~~ **retailer** may not have complied with clause~~s 13.256, 13.257 or~~ 13.259 (whether or not the **Authority** appoints an investigator to investigate the alleged breach), the ~~**generator retailer**~~ or **retailer** must pay the costs of the person who undertook the review.

(2) Despite subclause (1), if a report establishes, to the **Authority's** reasonable satisfaction that any non-compliance of the ~~**generator retailer** or~~ **retailer** is minor or there is any other reason in the **Authority's** view that means the ~~**generator retailer** or~~ **retailer** should not pay the costs of the person who undertook the review, the **Authority** may, in its discretion, determine the proportion of the person's costs that the ~~**generator retailer** or~~ **retailer** must pay, and the ~~**generator retailer** or~~ **retailer** must pay those costs.

(3) If a report establishes to the **Authority's** reasonable satisfaction that the ~~**generator retailer** or~~ **retailer** has complied with clause~~s 13.256, 13.257 and~~ 13.259 ~~(if relevant)~~, the **Authority** must pay the person's costs.

13.266 Requirement to provide complete and accurate information

(1) In addition to the requirements of clause 13.2, the ~~**generator retailer** or~~ **retailer** must take all practicable steps to ensure that the information that the ~~**generator retailer** or~~ **retailer** is required to provide to any person under clause~~s 13.256, 13.257 or~~ 13.259 is complete and correct.

(2) If a ~~**generator retailer** or~~ **retailer** becomes aware that any information the ~~**generator retailer** or~~ **retailer** provided under clause~~s 13.256, 13.257 or~~ 13.259 does not comply with subclause (1) or clause 13.2, even if the ~~**generator retailer** or~~ **retailer** has taken all practicable steps to ensure that the information complies, the ~~**generator retailer** or~~ **retailer** must, as soon as practicable, provide such further information as is necessary to ensure that the information provided complies with clause~~s 13.256, 13.257,~~ 13.259 or clause 13.2 (as relevant).

Questions

Q30. Do you have any comments on the drafting of the proposed Code amendments?

Appendix B Draft guidance to support Code amendments

B.1. This appendix provides draft guidance on how the Authority expects gentailers to comply with the non-discrimination principles. The guidance is intended to exist as a separate document, without being provided for in the Code itself.

Guidance on non-discriminatory supply (Principle 1)

(1) Non-discriminatory supply of risk management contracts between buyers

B.2. A **gentailer** should 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 other **buyers**.

B.3. When applying paragraph 1, a **gentailer** may consider differences in circumstances of trade including (without limitation) load factors, conditions of interruptibility, plant commitments, prudential requirements, time of contracting, scale efficiencies and duration of the relevant agreement.

B.4. To the extent any circumstances of trade referred to in paragraph B.3 above are reflected in commercial terms agreed with a **buyer** that are different to those agreed with another **buyer**, those different commercial terms should be based on objectively justifiable reasons.

B.5. For the purposes of the non-discrimination obligations, "objectively justifiable" is intended to require **gentailers** to apply an evidence-based approach that is reasonable, consistent and transparent. For the avoidance of doubt, when assessing whether a **gentailer's** reasons are objectively justifiable, the Authority may consider whether the **gentailer** has acted consistently with how a market participant without market power is likely to have acted in the circumstances.

(2) Non-discriminatory access to uncommitted capacity: gentailer internal business units vs buyers

B.6. A **gentailer's uncommitted capacity** to offer **risk management contracts** reflects its forecast ability to back a **risk management contract**. For the purpose of this forecast, at any point in time, future generation is uncommitted if the **gentailer** has not already allocated that generation to back:

a. existing **risk management contracts** entered into with **buyers**; or

b. **gentailer** market making commitments (regulated or voluntary), noting that where market making commitments to quote or offer do not result in a **risk management contracts**, the relevant generation then becomes uncommitted; or

c. the obligations the **gentailer** reasonably expects to have to supply to its end customers.

B.7. A **gentailer** should allocate its **uncommitted capacity** on a non-discriminatory basis, such that the **gentailer** does not prioritise supplying its **internal business units** over **buyers.**

B.8. A **gentailer** should, consistent with its record-keeping and disclosure obligations, keep records and make regular disclosures regarding:

d. its capacity to offer **risk management contracts;** and

e. any responses to **buyer** requests for **risk management contracts** where the response does not conform with all aspects of the buyer's request.

B.9. By way of further guidance, the non-discrimination requirements under subclause (2) of Principle 1 are not intended to:

f. require a **gentailer** to break existing end customer contracts

g. require a **gentailer** to stop acquiring, or to actively seek to divest itself of, end customers

h. allow a **gentailer** to allocate future generation capacity to planned growth in its own retail **internal business unit** without testing market interest in that capacity.

(3) Non-discriminatory pricing of risk management contracts: gentailer internal business units vs buyers

B.10. The Authority expects that **gentailers** will primarily satisfy subclause (3) of Principle 1 by demonstrating an economically justifiable link between the expected cost of electricity supply and its retail price offers, ie, passing the **retail price consistency assessment** that it is required to regularly perform.

B.11. The **retail price consistency assessment** is based on an 'as efficient as' standard, rather than a hypothetical measure of efficiency. This standard is intended to make the retail function of each gentailer into the benchmark for **retail price consistency assessments**. If gentailer X passes the **retail price consistency assessment**, and retailer Y is as efficient or more efficient than gentailer X's retail function, then retailer Y should be able to compete and earn a margin when purchasing a portfolio of **risk management contracts** from gentailer X.

B.12. The **retail price consistency assessment** will assess margin based on a portfolio of **risk management contracts** offered by the **gentailer**. Subclause (3) of Principle 1 may also apply to individual **risk management contracts** offered to **buyers**, eg, if there is good reason to consider that the price offered for that contract is materially higher than the internal value that the **gentailer** places on that hedge.

Guidance on obligation to trade in good faith (Principle 2)

B.13. The confidence in and efficiency of trading of **risk management contracts** is improved through encouraging high integrity conduct from all counterparties - which includes **gentailers** acting fairly, consistently and in good faith, and enabling their staff with the requisite skills, training, and support to perform their roles efficiently, effectively and professionally.

B.14. **Gentailers** should adopt trading practices and processes that are transparent, efficient, and objectively justifiable, and commit to ongoing improvement and monitoring of performance, both of the market as a whole and the individual participants, so as to ensure ongoing confidence in and efficiency of trading of **risk management contracts**.

B.15. **Gentailers** are expected to engage with **buyers** in a timely and constructive manner, for example by:

i. responding to **buyers'** requests for **risk management contracts** within 5 working days; and

j. allowing **buyers** at least 5 working days to respond to offers made in response,

unless there is an objectively justifiable reason for a longer timeframe being necessary.

Matters that may be taken into account

B.16. The Authority expects that the following list of matters will be relevant in determining whether the **gentailer** has engaged with **buyers** in good faith:

a. whether the **gentailer** has acted honestly;

b. whether the **gentailer** has been responsive and communicative;

c. whether the **gentailer** has not acted arbitrarily, capriciously, unfairly, or unreasonably;

d. whether the **gentailer** has not acted in a way that constitutes retaliation against a **buyer** for past complaints and disputes

e. whether the **gentailer** has observed confidentiality requirements relating to **buyer confidential information** (including in accordance with Principle 5)

f. whether a **buyer's** requests for **risk management contracts** are reasonable (for example, by providing reasonable timelines, by providing reasonably required information and being issued where there is a genuine intention to transact).

B.17. The matters set out above are not exhaustive, however, and do not limit the obligation on **gentailers** to engage with **buyers** in good faith and in a timely and constructive manner in accordance with Principle 2.

Guidance on credit assessments (Principle 3)

B.18. The credit terms and collateral arrangements offered by a **gentailer** in relation to the supply of **risk management contracts** to **buyers** should be a reasonable reflection of the risks of trading with the **buyer**. For this purpose, a **gentailer** should:

a. assess the credit worthiness of the **buyer** by reference to a range of relevant information, including information submitted by the **buyer**

b. follow an established and transparent process for assessing credit worthiness

c. consider, and where appropriate, discuss a range of credit options with the **buyer**

d. ensure that the credit terms and collateral arrangements offered reflect the outcome of the assessment, consideration and discussion under paragraphs B.18(a) to B.18(b).

Additionally, the **gentailer** should also be able to demonstrate to the Authority that it has done so.

2. The **gentailer** should process credit applications and conduct reviews in a timely, efficient and transparent manner. This includes:

a. providing an indication of when a decision might reasonably be made, subject to the applicant satisfying all reasonable information requirements in a timely manner

b. proactively notifying the applicant of any progress, including delays, issues or final decisions, when they become known.

B.19. The **gentailer** should submit to the **buyer**, with its offer, the basis for its credit decision.

Guidance on equal access to commercial information (Principle 4)

B.20. A **gentailer** should ensure that any **commercial information** relating to **risk management contracts** made available to its **internal business units** is also made available to **buyers** at the same time.

B.21. This is intended to ensure a **gentailer's** retail **internal business unit** does not receive a competitive advantage through access to **commercial information** regarding **risk management contracts**. For example, information regarding a **gentailer's** current and future capacity to offer **risk management contracts** should be made available to all **buyers** even-handedly.

Guidance on protection of confidential information (Principle 5)

B.22. In relation to the supply of **risk management contracts** by **gentailers** to **buyers**:

c. a **gentailer** should not disclose to an **internal business unit** information the **gentailer** has obtained through its dealings with a **buyer** where the disclosure would, or would be likely to, provide an advantage to the **internal business unit**

d. a **gentailer** should keep all **buyer confidential information** in confidence and should not disclose **buyer confidential information** to any third party other than as necessary for the provision of **risk management contracts** to that **buyer**, or where disclosure is:

i. in confidence, to an emergency organisation that reasonably needs that information

ii. properly made pursuant to a relevant legal or regulatory obligation

iii. to the Authority

iv. properly and reasonably made to a court

v. authorised by the **buyer**.

e. a **gentailer** should not use **buyer confidential information** for sales or marketing purposes

f. a **gentailer** should have robust processes in place to ensure that any **buyer confidential information** that is inadvertently disclosed to an **internal business unit** is not used by that **internal business unit** to gain an advantage.

Questions

Q31. Do you have any comments on the draft guidance?

Q32. Is any further guidance needed to help clarify what constitutes an “objectively justifiable” reason for discrimination under the NDOs? Please explain.

Appendix C Format for submissions

Submitter	

Questions	**Comments**
Problem definition	
Q1. Do you have any comments on our additional analysis of data to inform the problem definition? Do you have any new evidence to add to any of the elements of the problem definition?	
Level Playing Field options (options 1-4)	
Q2. Do you have any new evidence that is relevant to the choice of level playing field interventions to address the identified competition issues?	
Approach to applying non-discrimination obligations	
Q3. Do you have any feedback on our proposed approach to implementing principles-based non-discrimination requirements, as set out in Chapter 5? If you disagree with elements, how would you improve them?	
Q4. Do you agree that substituting an RPCA test for a requirement to develop an internal hedge portfolio will be more effective at ensuring non-discriminatory pricing than the proposals in the LPF Options paper? Why or why not?	
Q5. Is our proposal around “uncommitted capacity” workable? What suggestions do you have for improving it?	

Q6. Do you have any further evidence, particularly relating to costs or incentives, about the impact of applying NDOs to all risk management contracts rather than just super-peak hedges?	
Q7. Should large users be included as buyers under the NDOs? If so, is a carve out needed for risk management contracts approved under the MLC regime?	
Q8. Should the OTC Electricity Market Working Group be reconvened to assess whether any amendments might be made to the voluntary OTC Code of Conduct to reflect the proposed non-discrimination regime?	
Q9. Should investment in new flexible generation assets be carved out from the proposed NDOs? Why or why not? If you think new investment should be ringfenced, please provide details of how you suggest any carve outs be implemented.	
Q10. What impact do you think the revised NDOs will have on retail prices and/or incentives to invest in generation? How does this compare to the impacts you posited in response to the LPF Options paper? Can you share any evidence that supports your view?	
Retail price consistency assessment	
Q11. Do you agree that by providing transparency on margins, the RPCA would materially improve stakeholders' confidence that retailers compete	

on a LPF for the long-term benefit of consumers? If not, why? Can you share any evidence that supports your view? How could we adjust the test to further improve confidence?	
Q12. What impact do you think the RPCA will have on retail prices and incentives to invest in generation? How does this compare to the impacts you posited in response in the LPF Options paper? Can you share any evidence that supports your view?	
Q13. How could the proposed approach to the RPCA be improved?	
Q14. How often should gentailers make and disclose their assessment – should it be more or less frequent than every six months, and why?	
Q15. Would it be sufficient for the Authority to provide gentailers with guidance on the methodology for the RPCA or should it be prescribed in the Code, and why?	
Q16. If you do not support the RPCA approach, what would you propose instead to demonstrate compliance with non-discrimination principles?	
Implementation pathway	
Q17. Is the proposed implementation timeline achievable?	
Q18. Should the Authority consider adding or removing any	

particular steps, or providing more or less time at any point?	
Q19. Does the proposed approach to implementation provide the right balance between certainty, transparency and flexibility to allow gentailers to demonstrate their compliance with the non-discrimination obligations, and to provide an appropriate basis for enforcement action if they do not?	
Escalation pathway	
Q20. Do you support the revised approach of incrementally creating more specification for NDOs or the RPCA as required? Why or why not?	
Q21. What are your views on the proposed approach to the escalation pathway?	
Power Purchase Agreements	
Q22. Do you have any feedback, including suggestions for improvement, on the way that the NDOs will affect buyers seeking firming for PPAs?	
Q23. Would it be useful to convene a co-design group to consider a range of flexibility products that suit the needs of independent power generators?	
Internal Transfer Price disclosure requirements	
Q24. Do you support the proposal to revoke the ITP requirements for gentailers? What are your views on retaining the RGM reporting requirements for independent retailers?	

Regulatory Statement for the proposed amendment	
Q25. Do you agree with the objectives of the proposed amendment? If not, why not?	
Q26. Do you agree the benefits of the proposed amendment outweigh its costs?	
Q27. Do you agree the proposed amendment is preferable to the other options? If you disagree, please explain your preferred option in terms consistent with the Authority's statutory objective in section 15 of the Electricity Industry Act 2010.	
Q28. Do you agree the Authority's proposed amendment complies with section 32(1) of the Act?	
Q29. Do you have any comments on the regulatory statement?	
Appendix A – Proposed Code amendments	
Proposed Code amendments	
Q30. Do you have any comments on the drafting of the proposed Code amendments?	
Draft guidance to support Code amendments	
Q31. Do you have any comments on the draft guidance?	
Q32. Is any further guidance needed to help clarify what constitutes an "objectively justifiable" reason for discrimination under the NDOs? Please explain.	

Appendix D Full list of submitters

2degrees	Helios Energy
350 Aotearoa	Independent Electricity Generators Association
Bryan Leyland	Independent Electricity Retailers (IER), with an expert report from Link Economics
BusinessNZ Energy Council	Independent expert panel commissioned by Mercury (the Mercury panel), with expert reports from Houston Kemp, Concept Consulting, Sapere, and Carlson Consulting
Cognitus	Lodestone Energy
Common Grace Aotearoa	Major Electricity Users Group (MEUG), with an expert report from NZIER
Consumer NZ	Mercury
Contact	Meridian, with expert reports from NERA and Capital Strategic Advisors
David Riley	Neoen
D'Souza Associates	Northern Infrastructure Forum (NIF)
Ecotricity	Nova
Electric Power Optimization Centre (EPOC)	NZ Steel
Electricity Engineers Association (EEA)	Octopus Energy, with an expert report from FTI Consulting
Electricity Retailers Association NZ (ERANZ)	Patricia Scott
Energy Link	Pulse Energy
Energy Resources Aotearoa	Sinclair Electrical and Refrigeration
Entrust	Slowjam
EVA Marketplace	Smartwin Energy Trading
Fonterra	Sustainable Energy Association NZ (SEANZ)
Genesis, with an expert report from Sapere	Total Utilities
Geoff Henderson	Unison + Centralines

Confidential submitter	Vector

Appendix E Further analysis of super-peak prices

Purpose

E.1. The Authority tested Meridian's suggestions for adjustments to our RMR price benchmark to evaluate the competitiveness of OTC super-peak prices. Meridian did not claim all of these adjustments would significantly alter the analysis but noted some of the factors were likely adding noise to the analysis while acknowledging that it was not clear if these would have a bias in a particular direction. These suggestions were:[83]

- use a different percentile of historical spot prices to calculate shape premia as historical average spot prices may not represent future super-peak spot prices
- match South Island offers to Benmore prices and North Island offers to Otahuhu prices
- analyse whether using different super peak trading periods has an impact on the benchmark
- use ASX monthly prices for contracts equal to or less than a month in duration
- limit the period to calculate the shape premium to a shorter timeframe
- account for contracts for which there were no benchmark prices on the ASX at the time of responses.

Testing the impact of Meridian's suggestions

E.2. Meridian made several comments about the original approach used in the RMR when comparing super-peak contract offer prices to benchmark prices made up of ASX baseload + a shape premium, as calculated by the Authority.

E.3. The Authority tested the effects and found these were small whether considering each suggestion individually or in total.

Meridian: Use a different percentile instead of the historical average of spot prices for the calculation of the super-peak shape premia, as historical spot prices may not accurately represent future super-peak spot prices (and non-linearity in super-peak sport prices may be increasing due to increasing scarcity).
Response: The RMR used the average of historical spot prices. The impact of adopting a different percentile instead is small. As the price distribution is skewed, and the average is greater than the median and the 60th percentile, using any percentile that is less than the 60th percentile reduces the shape premium, increasing the difference between offered contract prices and the benchmark.

[83] The Authority also undertook an extensive review of the computational routines it used and found these to be working as intended.

The RMR calculated shape premia using data spanning from 1st January 2019 to 31st December 2023, averaged by quarters. Limiting this historical data to a shorter timeframe, averaging the prices by quarter according to request dates and quarters, similar to Meridian's approach did not noticeably affect results.
Meridian: Match SI offers to Benmore prices and NI offers to Ōtāhuhu prices.
Response: The RMR used Ōtāhuhu wholesale spot prices to calculate the shape premium for all comparisons. Matching offers to nodes in the same island had little effect on the offered contract prices. That is because differences in the super-peak ratios between these nodes are small.
Meridian: Trading periods used to define super-peak times are different from those they use to calculate the shape premium.
Response: Changing the RMR definition of super-peak trading periods (we used 13-20 for morning peak and 35-46 for evening peak) to trading periods as used by Meridian somewhat reduces the difference between the offered contract price and the benchmark.
Meridian: Use ASX monthly prices when comparing prices for contracts equal or lesser than a month in duration, rather than using ASX quarterly prices for all contracts.
Response: Incorporating this suggestion widens the distribution of the differences between contract and benchmark prices but does not significantly change the median compared to the original approach. Around 36% of the contracts were for 30 days or less.
Meridian: Contracts flagged as having a duration of 30 days or less might not be market made at the time of response [so there is no relevant ASX price to compare to]. Market-made monthly contracts must be priced no more than 6 months in advance
Response: Around 84% of contracts captured in our analysis were market-made (either quarterly contracts (or longer than a quarter) or were priced less than six months in advance).

Table 9: Super-peak ratios at BEN2201 and OTA2201 for 2019-2023

Qtr	Benmore (BEN2201)	Ōtāhuhu (OTA2201)
1	1.106	1.096
2	1.216	1.206
3	1.204	1.214
4	1.154	1.150

Source: Electricity Authority

E.4. The combined effect of implementing Meridian's suggestions is to scatter data more, and to create more points where contracts were priced lower than the ASX baseload plus shape premium benchmark. This indicates a slightly better alignment between OTC offered contract prices and the benchmark ASX prices + shape premium.

E.5. However, even with all the suggested changes there are still several contracts priced well above the benchmark.

Impact on Meridian’s contract prices compared to benchmark

E.6. After incorporating all Meridian’s suggested changes, a few of the contracts were still priced high. This was also the case for contracts from other gentailers.

E.7. High-priced offers tended to be for small (less than 150 MWh) and medium volumes (less than 2,500 MWh) and the highest-priced ones tended to have a duration of a month or less.

E.8. Contracts offered prior to 1st July 2023 were the ones usually priced higher.

E.9. Meridian disclosed that it has changed its methodology to price OTC contracts starting in mid-2023. Contracts priced after mid-2023 were more clustered and closer to benchmark prices, although this may also be related to market conditions at the time.

E.10. We also noted that around 15% of offered contracts were outside of the market making period, including three of the highest-priced contracts. At least two contracts traded and priced above $250/MWh were during the market making period but were priced using the old methodology. These contracts were for 30 days or less in duration.

E.11. Overall, we observed small changes from incorporating Meridian’s suggestions. Higher prices seem to align a little more with the ASX prices with premia. It seems that Meridian’s updated methodology and other information provided on its methodology for pricing contracts are informative in understanding Meridian’s contract offer pricing. Contracts lasting a month or less tended to be priced higher, some of those were not during the market making period, and most of them were priced using the old methodology.

E.12. It also seems that the methodology used by Meridian from mid-2023 onwards results in pricing of contracts that is reasonably consistent with the benchmark.

Offers from other participants

E.13. The Authority also tested the impact of applying Meridian’s suggested changes to offered super-peak contract prices made by other parties.

E.14. In general, there was better agreement between offered OTC contract price and the Authority’s benchmark price.

E.15. Mercury still showed high-priced offers for super-peak products, even for those offers within the market making period (12% of Mercury’s contracts were outside of the market making period). The Authority considers this likely reflects that Mercury almost always makes offers, even when they face capacity constraints, though our analysis cannot confirm this. However, the Authority notes that recent data on standardised flexibility product transactions indicate Mercury’s prices are in line with other transactions.

E.16. Contact’s high-priced offers (compared to the benchmark) were outside the market making period (40% of their offers fell outside this period).

E.17. The very small number of super-peak offers made by Genesis and Mercuria do not lend themselves to further analysis.

Appendix F Additional analysis on substitutes

F.1. The Authority undertook additional analysis of substitutes for super-peak hedges under additional scenarios of more intermittent generation, higher spot price volatility and higher prices at super-peak times.

F.2. The additional analysis confirms that a portfolio of baseload and cap hedges, baseload and battery services, and baseload and peak are effective substitutes to a portfolio of baseload and super-peak under alternative scenarios.

Summary of Risk Management Review findings

F.3. The substitutability analysis in the RMR tested how much contract spend would shift following a 5% price increase in a particular option,[84] based on a baseline scenario.

F.4. The RMR found that:[85]

- All retailers managing wholesale price risk use a portfolio of complementary risk management options — there is no one 'right' solution when insuring against wholesale electricity market volatility.
- There are several close risk management substitutes for an OTC contract-based portfolio (baseload hedges and a super-peak hedge), for example, baseload hedges combined with one of: battery renting, demand response, or retail tariffs.
- Risk reduction from a portfolio of shaped hedges (baseload, peak, and super-peak hedges) is similar to that from a portfolio of baseload hedges with peak hedges, demand response, battery investment, and C300 cap hedges.

F.5. The baseline in the RMR was modelled off 40 market states, starting with 2023 spot prices and demand for a hypothetical independent retailer, and then varying the spot price and/or the independent retailer's demand.

F.6. Under this baseline scenario, a 5% price increase in super-peak contracts would result in a significant shift in contract spend towards other products:

- spending on super-peak products (within a portfolio of hedge products that includes a baseload and peak contracts) falls – by $26.9 million per annum as shown in the green cells of Table 10.
- spending shifts to peak products - by $28.4 million per annum as shown in the green cells of Table 11.

F.7. Similar patterns are observed for the other risk management products in these tables (just baseload, +cap 300, or +battery)

[84] The test specifically recalculates the optimal split (that maximises the E-CVaR) in a portfolio consisting of a baseload hedge and up to two other products, for different price mark-ups on one of these other products.

[85] A detailed overview of the substitutability analysis is set out under Appendix B: Modelling methodology and results of the RMR.

Table 10: Given baseload contract and option 2 (only baseload if option 1 = option 2) are available at risk-neutral price - How much is spent on risk management option 1 if its price increases by 5% ($m pa)

Option 1	Price increase in option 1	Option 2			
		Peak	Super-Peak	Cap (C300)	Battery
Peak	None	158.6	41.1	73.4	120.1
	5%	0	0	0	0
Super-Peak	None	32	43.2	28.3	43.2
	5%	5.1	36.1	6.4	15.1
Cap (C300)	None	9.9	6.1	15.9	10.2
	5%	1.6	0.9	15.2	9.4
Battery	None	3.7	0	5.3	11.3
	5%	1.6	0	3	10.4

Table 11: Given baseload contract and option 2 (only baseload if option 1 = option 2) are available at risk-neutral price - How much is spent on baseload and risk management option 2 if the price of option 1 increases by 5% ($m pa)

Option 1	Price increase in option 1	Option 2			
		Peak	Super-Peak	Cap (C300)	Battery
Peak	None	230.4	346.4	311	270
	5%	392.1	387	382.7	388
Super-Peak	None	355.5	343.8	356.4	343.8
	5%	383.9	350.2	376.1	373.3
Cap (C300)	None	374.5	378.6	366.8	374.3
	5%	386.2	385.1	367.6	376
Battery	None	386.3	387	379.3	376.7
	5%	387.7	387	381	377.8

Further substitutability analysis under different scenarios

F.8. The substitutability analysis above has been retested under three different scenarios:

- **More intermittent generation**: When power generation is more intermittent, peak contracts prices fall, and super-peak contract prices rise a bit.
- **Higher spot price volatility**: When spot prices fluctuate more, the price for super-peak contracts increases a bit more than the price for peak contracts.
- **Higher super-peak prices**: When spot prices during super-peak periods are increased (reducing prices outside the super-peak), their price increases much more than that of peak contracts.

F.9. The analysis found that each alternative scenario leads to a slightly larger decrease in the amount of super-peak contracts purchased, compared to the baseline scenario.

Figure F1: Risk adjusted profit for portfolio, given more intermittent generation

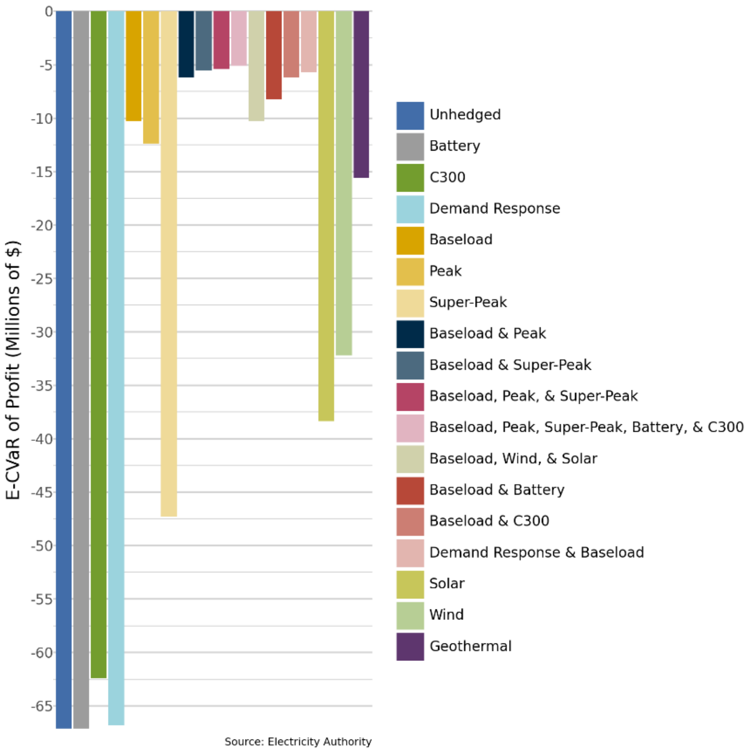


Figure F2: Risk adjusted profit for portfolio, given higher spot price volatility

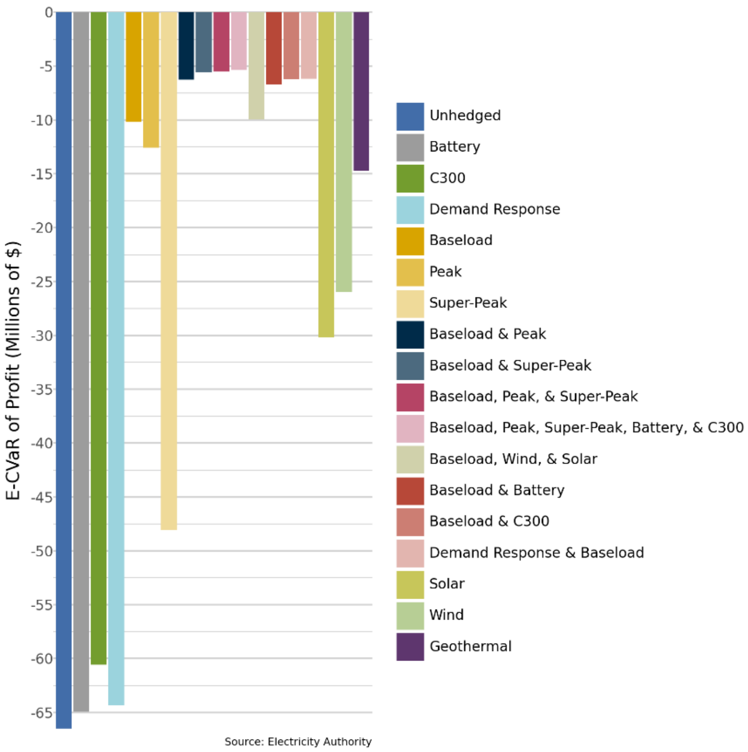
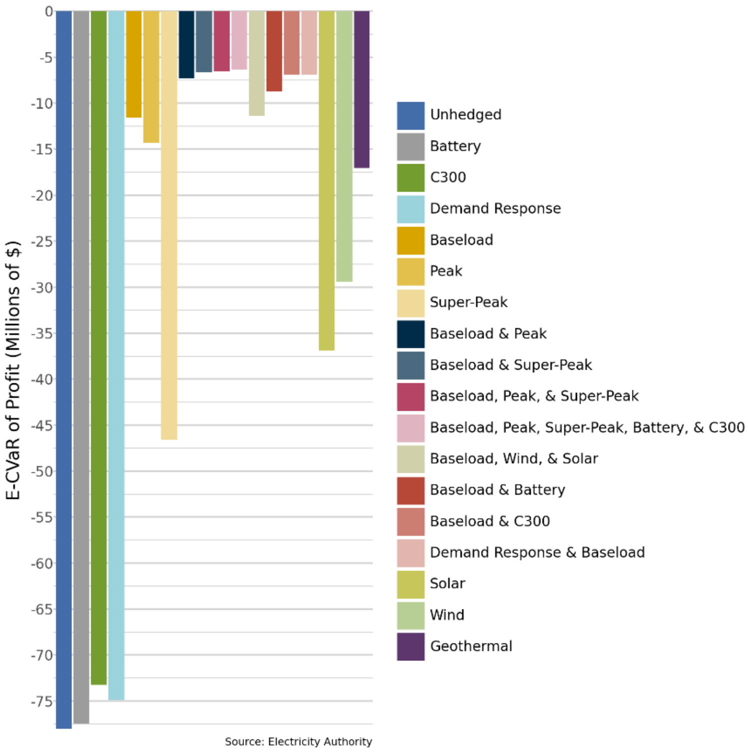


Figure F3: Risk adjusted profit for portfolio when higher prices at super-peak



Substitutability under more demand certainty

F.10. The substitutability analysis in the RMR was based on market states that contained uncertainty about what would happen to spot prices and customer load.

F.11. To further test the extent of substitutability between a portfolio of baseload and super-peak, and a portfolio of baseload and peak products, further modelling has been undertaken with demand uncertainty removed.

F.12. If independent retailers are relatively certain about their own future demand, for example given the specific profile of their customers, they will be able to hedge more effectively against future outcomes with fixed volume contracts. More demand certainty can impact the extent to which certain risk management products are substitutable for one another.

F.13. We find that super-peak contracts become somewhat less substitutable with more certainty in demand. A portfolio with super-peak hedges would reduce risk to profit somewhat more than other options with similar risk reduction effects under demand uncertainty.

F.14. The following figures compare the risk adjusted profit under the baseline scenario with and without demand certainty. These results exclude seasonal premiums – that is they just use risk neutral prices.

F.15. The risk adjusted profit losses for most portfolios are less in the scenario with demand certainty relative to the scenario with demand uncertainty, though in absolute terms the differences are not large.

Figure F4: Portfolio optimisation scenario risk adjusted profit given each portfolio – Without demand certainty

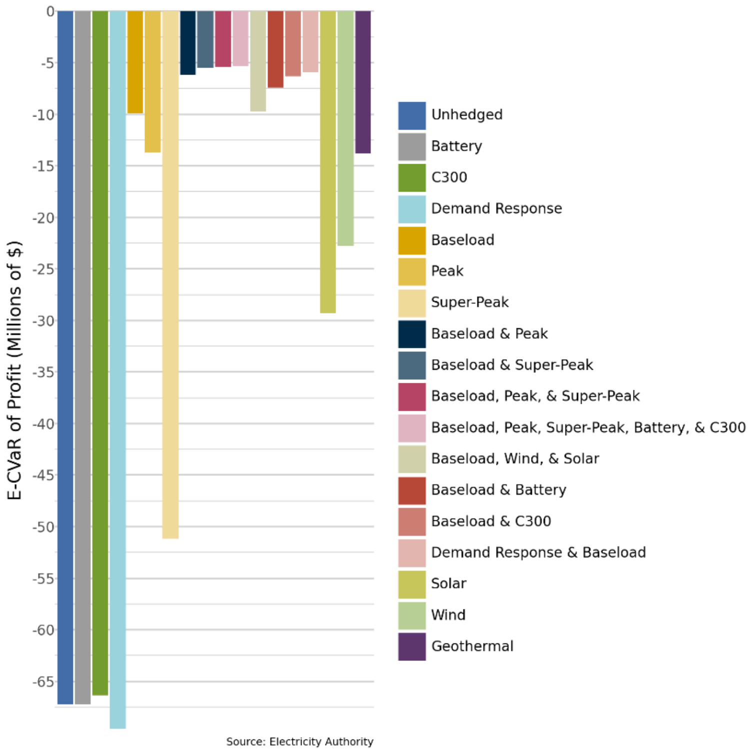
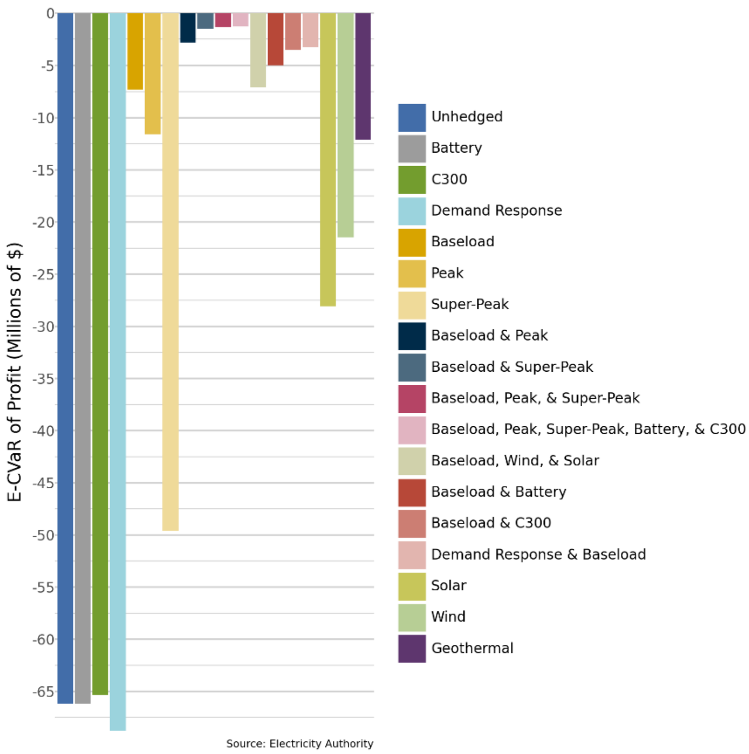


Figure F5: Portfolio optimisation scenario risk adjusted profit given each portfolio – With demand certainty



Appendix G Approach to assessing costs and benefits

Costs

G.1. Estimates of the costs of administering and compliance with the proposed Code are based on the Authority's assessment of possible resource requirements for material additional activities.

G.2. Assumptions reflect the Authority's experience with respect to its monitoring, compliance, and reporting functions, guidance development and Code implementation.

G.3. Estimates of resource requirements for gentailers took into account recent proposals and submissions concerning information disclosures (e.g. retail data project, OTC disclosures).

G.4. Estimated resource requirements were multiplied by staff costs. We assume a $200,000 annual cost per FTE (or $3,846 per week). This covers remuneration and operating expenses. FTE costs are on the basis that the tasks likely require professional input and senior oversight.

G.5. The first year includes set-up costs for the Authority and gentailers. These would cover such tasks as the technical design of the retail price consistency assessment, developing internal policies and processes consistent with the NDOs and delivering training, and the process of preparing and reviewing interim reports.

G.6. We assume costs fall within +/- 25% of these estimates.

Table 12: Breakdown of annual costs

Year 1 (set up)					**Ongoing p.a.**			
EA	**FTEs**	**Weeks**	**Unit cost**	**Total**	**FTEs**	**Weeks**	**Unit cost**	**Total**
Monitoring	3	52	3,846	$ 600,000	2	52	3,846	$ 400,000
Compliance	2	52	3,846	$ 400,000	2	52	3,846	$ 400,000
Legal	2	52	3,846	$ 400,000	1	52	3,846	$ 200,000
Policy	2	52	3,846	$ 400,000	1	52	3,846	$ 200,000
Consultants			400,000	$ 400,000			250,000	250,000
Total				**$ 2,200,000**				**1,450,000**

Year 1 (set up)					**Ongoing p.a.**			
Gentailers	**FTEs**	**Weeks**	**Unit cost**	**Total**	**FTEs**	**Weeks**	**Unit cost**	**Total**
Set up RPCA	1	12	300	$ 144,000				$ -
Set up policies	2	16	3,846	$ 123,077				$ -
Annual training on and review of policies					0.2	52	3,846	$ 40,000
Keep records/disclose	1	13	3,846	$ 50,000	1	13	3,846	$ 50,000
Interim report	2	12	3,846	$ 92,308				
Annual reporting	2	4	3,846	$ 30,769	2	4	3,846	$ 30,769
(+ auditor, added cost)	1		10,000	$ 10,000			10,000	$ 10,000
Breach self-reporting	1	2	3,846	$ 7,692	1	2	3,846	$ 7,692
Breach investigations				$ 50,000				$ 50,000
6 month RPCA reports	1	8	$ 3,846	$ 30,769	1	8	3,846	$ 30,769
Total per organisation				$ 538,615				$ 219,231
Rounded				$ 540,000				$ 220,000
Total				**$ 2,160,000**				**$ 880,000**
Total				$ 4,360,000				$ 2,330,000
Low				$ 3,360,000				$ 1,830,000
High				$ 5,360,000				$ 2,830,000

Benefits

Conceptual approach

G.7. In its assessment of costs and benefits of the proposal, the Authority focuses on the efficiency impacts from promoting competition for the long-term benefit of consumers.

G.8. If improved competition reduces retail prices, then this would result in both efficiency gains and wealth transfers from producers to consumers. When consumers pay less for electricity this creates (potentially sizeable) transfers from producers to consumers.

G.9. There are limits to the extent such transfers are in the consumers' long-term interest. If somehow a policy forces prices below the social marginal cost of supply, then the proposal undermines producers' economic profits and incentives to supply and invest. This would not be for the long-term benefit of consumers.

G.10. As such, as is common in cost benefit analyses, the Authority focuses on whether the proposal improves consumer surplus, net of any transfers. This is indicated graphically by the "triangle" in Figure G1 (which for simplicity assumes constant marginal cost of supply). This measures the welfare improvement (additional consumer surplus) from consumers using more at lower prices.

G.11. This "triangle" is the full extent of the efficiencies if the 'post intervention' price were now to represent the marginal cost of electricity supply. That is, if the retail price is reduced all the way to the social marginal cost of electricity supply.

G.12. If, however, the reduced price remains above social marginal cost then the full efficiency effect includes the "rectangle" in Figure G1.

G.13. In practice, retailers' variable charges for electricity supply are likely to be above social marginal costs because a share of electricity supply costs, including network costs, are fixed in nature, but are recovered via variable consumption charges.

G.14. Such a price distortion would suppress consumption, creating a deadweight loss. This deadweight loss exists irrespective of the extent to which discriminatory supply of hedge products raises retail prices. To the extent that the proposed NDOs reduce prices and increase consumption (via competition driving lower prices), they also eliminate some of this pre-existing deadweight loss.

G.15. Variable charges are very likely to be above social marginal cost. In part this is due to the Low Fixed Charge regulations, which are being phased out, and in part due to historic network pricing practice. The latter is changing as a result of the new transmission pricing methodology and as electricity distribution businesses are evolving their pricing in line with the distribution pricing principles.

G.16. Sense Partners had estimated that the share of retailer revenue from fixed daily charges was 20% in 2024 (up from 13% in 2021).[86] The Authority estimates that a

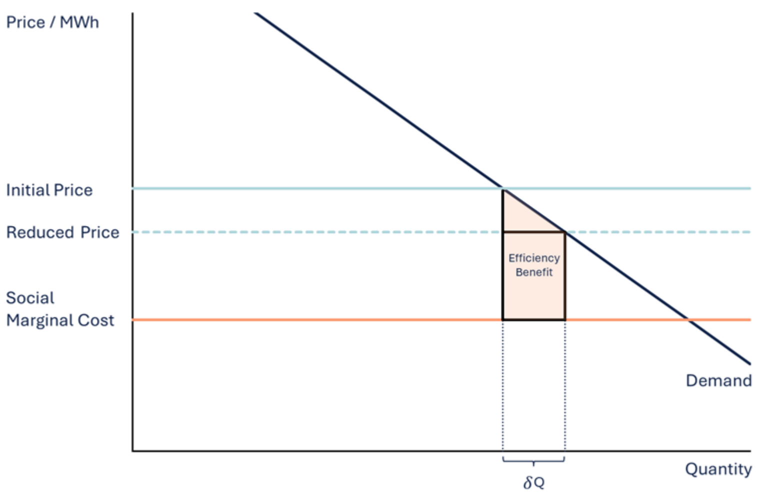
[86] Sense Partners, "Phase out of the Low Fixed Charge regulations: Quantified price effects for the first three years," October 2024, 28, https://www.mbie.govt.nz/dmsdocument/30584-sense-partners-report-lfc-phase-out-pdf.

more cost-reflective share of residential retail revenue from fixed daily charges would likely be 33% (putting aside any fixed costs of retailing). As at March 2025, network charges made up 39% of residential retail prices, and assuming ~85% of network prices are fixed then 85%*39%= 33%.

G.17. In Figure G1 the “rectangle” appears as an increase in producer surplus. In practice some or all of this is likely to be passed onto consumers in lower variable prices as fixed costs are spread across a larger volume of electricity supply. If so, this would generate further efficiencies and an increase in consumer surplus.

G.18. While this is a relevant benefit, its size is uncertain, because it depends on the effectiveness of the phase-out of the Low Fixed Charges, and the evolution of distribution pricing. As such, our break-even analysis focuses on the standard consumer surplus impact, but the Authority notes the potential benefits of these additional efficiency benefits as part of its assessment as discussed further below.

Figure G1: Conceptual approach to benefit assessment



Broad approach to estimating benefits

G.19. The regulatory statement sets out the logic of how the proposal is intended to deliver benefits in the form of lower prices over time, compared to the counterfactual. In summary this occurs by either:

- limiting any actual significant exercise of market power that would otherwise drive out competition and lift retail prices over time (whether that is by addressing the risk of persistent exercise of market power now, or the risk that this may happen in future)
- lifting confidence that the playing field is level and so promoting more entry and expansion by competing retailers and generators.

G.20. The lack of a robust basis to inform *how much* the proposal would impact prices means that we focus on identifying the break-even point – that is, how much retail prices would need to reduce for gains in consumer (or total) surplus to just offset the estimated cost.

G.21. This provides a basis to assess whether the order of magnitude of impacts is plausible.

Assumptions on retail prices, and modelling the effect of the proposal

G.22. The reduction in prices needed for the proposal to at least break-even would increase consumer surplus.

G.23. We estimate the consumer surplus impact from published data on volumes and average prices per kWh (Table 13) and applying an estimate of price elasticity of demand (discussed below).

G.24. There is a risk, however, that the reduction in price needed for break-even would be so large as to cause the resulting price to be below the social marginal cost. (That is, if the price reduction is larger than any markup from the exercise of significant market power). In that case the gain in consumer surplus would be offset by some loss in producer surplus (and so cause longer term harm to consumers by discouraging supply and investment).

G.25. For this evaluation, we adopt a cost of 17.5 c/kWh as a proxy for the social marginal cost of energy per kWh.[87] This estimate is based on an average cost of ~$165 for long-dated futures at Otahuhu during 2024 adjusted for shape. This provides one check against the risk set out in the paragraph above, though the estimate does not include an allowance for marginal retailing costs and the like.

G.26. The risk may not become an issue. First, the risk appears small, given the estimated costs of the proposal are very small in the context of total sales: $2.3m ongoing costs in the context of $10.5b sales per annum.

G.27. Second, the variable prices tend to be well above social marginal cost because they recover fixed costs, as discussed above. (The recovery of fixed costs through variable rates creates distortions or deadweight losses by overstating the marginal cost and thus reducing consumption.)

Table 13: Electricity volumes and prices by end user type, March 2025

Year to March 2025				Cents per kwh			
per year	GWH	kwh per icp	ICPs	Lines	Energy+	Total	Revs $M
Residential	14,044	7,477	1,884,497	13.57	21.00	34.57	4,855
Commercial	9,175	47,704	193,735			23.56	2,162
Industrial	12,435	273,323	44,814			22.62	2,813
Primary	2,619	30,613	85,697			25.73	674
	38,273		**2,208,743**	7.75	19.70	27.44	**10,503**

Source: MBIE Energy prices, MBIE Electricity statistics

G.28. As a further check, therefore, the Authority has sought to estimate how much of fixed charges, approximately, are in residential and other consumers' variable c/kWh rates.

87 We acknowledge that this is an average per kWh cost, rather than marginal cost per se, to fit with the reliance on average end user rates published by MBIE.

G.29. For this, the Authority drew on research by Sense Partners, who found that the share of retailer revenue coming from fixed daily charges was 20% in 2024 (up from 13% in 2021).[88] Based on average retail rates as at March 2025, this is 6.9 c/kWh, or an average daily charge of $1.42.

G.30. With network costs accounting for (13.57/34.57) = 39% of average retail rates as at March 2025 (Table 13), and assuming 85% of network prices are fixed, a more cost-reflective share of retail revenue from fixed daily charges would be (85% x 39%=) 33%. This ignores any fixed costs of retailing,

G.31. Applied to average retail rates shown in Table 13, this is the equivalent of 11.5 c/kWh, or an average daily charge of $2.36. This suggests that (11.5-6.9=) 4.6c per kWh of variable retail rates would be more efficiently charged through fixed charges. See Table 14.

G.32. The Sense Partners research also identified that electricity distributors collected 77% of their revenue (from retail customers) through variable charges in 2021, though that was reducing, and was expected to be 60% in 2024, instead of (1-0.85=) 15%.

G.33. For simplicity, we assume a similar share applies to the other consumer groups (acknowledging that some industrial consumers will be connected directly to the grid). This would suggest that 2 c/kWh of their current variable rates would be more efficient charged through fixed charges.

G.34. Taking a volume weighted average, it implies that across all market segments ~2.9 c/kWh are recovered via variable retail rates that are more efficiently recovered through fixed charges, and this provides another check on how much end users' average c/kWh rates could reduce without these rates going below the social marginal cost of supply.

Table 14: Assumption on share of fixed costs recovered via variable charges

Share of fixed costs recovered via variable charges, 2024			
	Estimated	Expected	Excess c/kWh
Network costs	60%	15%	
Retail	20%	33%	
Fixed component as c/kwh	6.9	11.5	**4.6**
=Daily charge $	$1.42	$2.36	
Commercial/Industrial	60%	15%	2.0
Total:			**2.9**

Source: Sense Partners, op cit. pp 25- 28, and EA calculations

G.35. The Authority also considered other approaches, including if it could determine the potential size of markup, as a result of any exercise of significant market power in access to or pricing of risk management contracts, that may be present in end user prices now (or could turn up once competition from independent retailers and generators had been deterred), and so could be amenable to being reduced or eliminated by the proposal.

88 Ibid, 28.

G.36. On average, super-peak contract prices have been more than 30% over the benchmark ASX baseload + shape used in the RMR. In principle, this could be used to estimate the size of any markup in retail rates and so provide an estimate of the competitive (social marginal) cost of supply.

G.37. However, this approach appears more speculative than informative, in part because the RMR concluded that the premium over the ASX baseload+shape likely reflected scarcity though there was a risk it may reflect anticompetitive conduct, and the extent of risk was not quantified.

Impact of NDOs assumed to ramp up over three years

G.38. Change usually takes time, and it is unrealistic to assume the NDOs will be fully effective from the first day. Even so, the intent is that NDOs do have an impact early on. For the purpose of our break-even analysis, benefits are assumed to ramp up over three years: year 1 achieves 33% of any effect, year 2 66% and year 3 100%.

Other parameters

G.39. Other key assumptions cover:

- price elasticity of demand. We assumed an elasticity of -0.45, acknowledging evidence in the literature of inelastic demand in the short run (e.g. -0.2) and elastic demand in the long run (e.g. -0.7 and even more elastic).
- demand growth. We assumed 1.7% demand growth per annum, drawing on the reference case in MBIE's 2024 EDGS (within a range of 1.1-2.2%), reflecting different electrification scenarios.[89]

Scenarios and results

G.40. Table 15 sets out key assumptions for our main or 'central' scenario and two alternative scenarios where we assumed (from the ranges above) the values for costs, price elasticities and demand growth rates that would result in lower or higher required changes in prices needed to break even.

Table 15: Alternative assumptions to test sensitivity of results

Scenarios	Main	Low	High
Year 1 costs $m	4.4	3.4	5.4
Cost (ongoing) $m pa	2.3	1.8	2.8
Price elasticity	-0.45	-0.7	-0.2
Demand growth pa	1.7%	2.2%	1.1%

G.41. We then estimate by how much end-user prices would have to reduce for the proposal to break even, in terms of a zero net present value of consumer surplus. Key results are presented in Table 16.

89 MBIE, "Electricity Demand and Generation Scenarios: Results summary," July 2024, https://www.mbie.govt.nz/assets/electricity-demand-and-generation-scenarios-report-2024.pdf.

G.42. The change needed in end users' c/kWh prices for the proposal to break-even is a permanent shift in the level of long run prices, compared to the counterfactual. It is assumed to occur in steps over the first three years.

G.43. All results are below the 2.9 c/kWh check set out in paragraph G.34. At 2.7 c/kWh, the 'High' scenario when applied to mass market consumers only edges close to, but does not exceed, that check. It also gets close to but does not exceed the estimate of the 'marginal' cost of energy at G25.

G.44. The Authority considers these estimates provide a useful input (alongside other, non-quantified, factors) into considering whether the benefits of the proposal are likely to exceed its costs.

Table 16: Summary results

	All consumers			Mass market retail only		
Scenarios	**Main**	**Low**	**High**	**Main**	**Low**	**High**
Present value of costs $m	26.8	21.0	32.6	26.8	21.0	32.6
Change in c/kWh needed	-0.86	-0.59	-1.46	-1.59	-1.10	-2.71
% change in price needed	-3.1	-2.2	-5.3	-4.6	-3.2	-7.8
Change in quantity GWh	538	578	408	290	312	220
NPV consumer surplus $m	**0**	**0**	**0**	**0**	**0**	**0**

Source: EA calculations.

Appendix H Glossary of abbreviations and terms

Glossary	
Act	Electricity Industry Act 2010
ASX	Australian Securities Exchange. Some standardised risk management contracts are traded via the ASX. They all have standardised terms (monthly or quarterly), profiles (baseload) and nodes (OTA or BEN)..
Australian NEM market	National Electricity Market, operating in the eastern and south-eastern states of Australia
Authority	Electricity Authority
Baseload	A fixed volume of energy traded during a fixed period for a fixed price, for all trading periods (same volume in each trading period).
Buyer (or Owner)	The buyer (or owner) is the entity that purchases the electricity either from the spot market or via contracts/futures. A more specific definition is proposed for the proposed Code drafting.
Cap	A fixed volume of energy is traded during a fixed period for a fixed price but only when the spot price exceeds a specified price. The standard cap contract traded in the market is a "$300 cap". This means the seller of a cap is required to pay to the buyer the difference between the spot price and $300/MWh every time the spot price exceeds $300/MWh during the specified contract period.
CfD	Contract for differences. This is defined in the Code as a financial derivative contract: i. Under which one or both parties makes or may make a payment to the other party; and ii. In which the payment to be made depends on, or is derived from, the price of a specified quantity of electricity at a particular time; and iii. That may provide a means for the risk to 1 or both parties of an increase or decrease in the price of electricity to be reduced or eliminated; and iv. That either— v. Relates to a quantity of electricity that equals or exceeds 0.25 MW of electricity; or vi. Is entered into through a derivatives exchange, being a market in which parties trade standardised financial

	derivative contracts, and contracts containing the right to buy or sell standardised financial derivative contracts, with a central counterparty
Code	Electricity Industry Participation Code 2010
CVaR	Conditional Value at Risk - A metric used to measure risk, used here to assess risk of one hedging strategy relative to another. It measures the average loss beyond the Value at Risk (VaR). For example, if a portfolio has a 20% CVaR of $1,000,000 over a quarter, the expected loss of the portfolio across the worst 20% of all scenarios is $1,000,000 over a quarter.
Derivative	A financial product whose value is based on (derived from) another product. An arrangement or product (such as a future, option, or warrant) whose value derives from and is dependent on the value of an underlying asset, such as a commodity, currency, or security.
Exercise	The action taken by the holder of an options contract to either buy (in the case of a call option) or sell (put option) the underlying commodity or financial instrument at the specified strike price.
Firming	Ensuring that intermittent power generation (like wind and solar) can reliably meet demand by supplementing it with other energy sources or storage solutions.
Firming contract	An agreement that ensures the availability of a specified amount of electricity supply during times when it is needed, especially when dealing with variable or intermittent generation sources, such as wind or solar power.
Flexible generation	The ability to increase or decrease the amount of electricity produced, by turning generation on or off when needed (or ramping output up or down). Hydro is the most common type of flexible generation. Most flexible generation assets are controlled by the gentailers. Ownership of those assets underpins the ability to offer shaped hedge contracts and firming for intermittent generation.
FRAND	Fair, reasonable and non-discriminatory.
Futures	In relation to the NZ electricity market, futures are financial contracts purchased or sold by those who wish to hedge or speculate on the underlying spot market prices of a certain amount of electricity for a future period, such as a month or a quarter. These contracts are traded on the Australian Securities Exchange (ASX).
Gentailer	Generator-retailer - an electricity company that operates both as a generator and a retailer of electricity.

GPS	Government Policy Statement, specifically the Statement of Government Policy to the Electricity Authority under section 17 of the Electricity Industry Act 2010, issued in October 2024
Hedge, hedge contract	A way of reducing or eliminating one's exposure to risk in a market. For example, non-integrated retailers are exposed to the risk that the spot price of electricity will be higher than the price for which they have already agreed to sell electricity to their customers. To eliminate this risk they can buy an over-the-counter hedge contract from a gentailer that guarantees them electricity at a certain price instead of the spot price during a future period. Hedging is a risk management strategy.
Hedge market	The hedge market in New Zealand is primarily the electricity futures market (run by the ASX) and the OTC market for risk management contracts. This paper uses the term "hedge market" as shorthand for the broader risk management contract market, which includes options and physical supply agreements.
ICP	Installation control point number. A unique 15 digit number that identifies a connection to the electricity network.
Independent retailer	See non-integrated retailer
Intermittent generation	Generation such as wind or solar power that may not be able to generate at times when its fuel source is unavailable (for example, if there is no wind or it is cloudy). The more intermittent generation there is in the system, the more flexible capacity is required to firm it.
ITP	Internal transfer price of a gentailer. It is a notional transfer price used in accounting practice that represents the price that one division in a company charges against another division (in this case wholesale charges retail). The Code currently mandates ITP reporting by gentailers.
LCOE	The levelised cost of electricity - Most calculations of the LCOE for a particular technology are the sum of the costs over the lifetime divided by the sum of electrical production over the lifetime. This calculation gives a value of the electricity produced as $/MWh. Levelised cost of electricity (LCOE) = total lifetime costs ÷ total lifetime electrical production
Level playing field measures	Level Playing Field measures are measures that are designed to ensure fair and even-handed access treatment of all participants in a market. They can range from disclosure obligations to structural remedies like corporate separation.

LFC	Low Fixed Charge. The LFC regulations put a cap on daily fixed charges for residential electricity users who are "low users" (as defined in the LFC regulations). The LFC is being phased out.
Liquidity	Liquidity refers to how easily and quickly a buyer or seller can enter into a transaction, without causing a major change in price and without incurring significant transaction costs.
Long Run Marginal Cost (LRMC)	LRMC is the cost of expanding supply. This includes LCOE for the lowest cost mix of new generation plus the cost for firming that new generation.
Margin squeeze	A margin squeeze is an anti-competitive practice where a vertically integrated, dominant firm charges prices for an essential input to its competitors, and sets its own downstream price, in such a way that equally efficient rivals cannot profitably compete in the downstream market.
MDAG	Market Development Advisory Group - The group provided independent advice on issues that relate to pricing and cost allocation, risk and risk management, and operational efficiencies. Group was formed in October 2017 and disbanded in February 2024.
MLC	Materially Large Contracts, defined in subpart 7 of part 13 of the Code. It refers to a contract where the buyer will consume at least 150MW itself.
MSOF	Mandatory Supply of Firming, a form of virtual disaggregation
Non-Discrimination Obligations (NDOs)	Non-discrimination obligations are a level playing field measure that, in relation to the supply of risk management contracts, would require gentailers not to treat themselves substantially differently from their non-integrated competitors, or to treat different competitors substantially differently.
Non-integrated retailer	A retailer that does not own generation.
Option	Financial contract containing the right, but not obligation, to buy (call option) or sell (put option) a commodity or financial instrument at the specified strike price. It is the option to exercise a contract.
OTC	Over-the-Counter. Contracts for the purchase and sale of electricity hedges that are traded bilaterally rather than on an exchange. Bespoke contracts between two parties (buyers negotiate directly with sellers). Because it is bespoke, the contract can be for any node(s), term, profile or payment terms that the two parties agree on..

OTC Code of Conduct	A voluntary code of conduct for participants in New Zealand's over the counter electricity market.
Peak	A fixed volume of energy is traded during a fixed period for a fixed price, for all trading periods during the day (same volume in each trading period). For peak contracts on the ASX, these trading periods cover 7am to 10pm.
PPA	Power purchase agreement. A PPA is a long-term agreement between an offtaker/purchaser and an asset owner/generator that allows the offtaker to purchase electricity on a long-term basis for a price level agreed by the parties.
Premium	Fixed amount paid for the rights to buy or sell a contract.
Regulations	Electricity Industry (Enforcement) Regulations 2010
Retail Gross Margin (RGM)	Represents the revenue received by a retailer after electricity, metering, levies, and distribution costs. For gentailers, the electricity cost used is based on their ITPs.
Retail Price Consistency Assessment (RPCA)	An assessment of the difference between a gentailer's expected cost of electricity supply and that gentailer's retail price offers. A novel concept outlined in more detail in Chapter 6.
RFP	Request for proposal - a request to get bids or proposals from service providers. The RFP outlines the requirements, scope of work, and expectations for potential suppliers to follow in their responses.
Risk management	The strategies of forecasting and evaluation of financial risks together with the identification of procedures to avoid or minimise their impact.
Risk management contract	A term defined in the Code, which covers contracts for difference, options contracts, and fixed-price physical supply contracts. This paper has used the term "hedge" and "hedge market" to refer imprecisely to risk management contracts and the market for them.
Risk premium	A measure of the excess return that is required by an individual to compensate being subjected to an increased level of risk.
RMR	Risk Management Review. An Electricity Authority publication, with the full title: "Reviewing risk management options for electricity retailers – issues paper"
Rulings panel	The Rulings Panel is an independent body that hears and determines complaints about breaches of the Electricity Industry Participation Code 2010 (Code).

Seller (or Writer)	A seller (or writer) refers to the party that issues a contract. This party is responsible for fulfilling the obligations of the contract if the buyer (or holder) decides to exercise their right.
Shaped products/ contracts	A customised financial instrument designed to meet specific load profiles or consumption patterns of end users. Unlike standard products, shaped products can account for variations in demand over different times of the day or seasons, allowing customers to better match their energy supply with their actual usage.
Sleeving	A retail service that enables an end user to give effect to a PPA by paying different prices for PPA and residual volumes.
SSNIP test	A test to define the relevant market from a competition perspective. The SSNIP test asks whether a hypothetical monopolist seller of a particular product could profitably implement a “Small but Significant (5-10%), Non-transitory Increase in Price”. If so, then the market is correctly defined as being limited to that product. If not, then there are likely substitute products that consumers are switching to in response to the price rise, so they should be included in the market definition, and the SSNIP test repeated, until it is met.
Standardised flexibility product	A new, standardised super-peak hedge OTC contract that was co-designed with industry and announced in December 2024.
Super-peak hedges	A contract for a fixed volume of energy at “super-peak” times of consumer demand – ie, morning and evening peaks.
Uncommitted capacity	A gentailer’s capacity to offer risk management contracts in future periods, with a proposed definition in the draft Code amendment.