ELECTRICITY AUTHORITY
TE MANA HIKO

Reviewing risk management options for electricity retailers – issues paper

7 November 2024

Executive summary

The Electricity Authority Te Mana Hiko commenced a risk management review in December 2023 to *test whether the availability of over-the-counter (OTC) risk management contracts, in the context of other risk management options, is creating a barrier to entry or expansion in the retail electricity market, and therefore harming competition*.

Risk management matters because it is a significant enabler of competition in the retail electricity market, especially for those retailers focused on domestic consumers and small business customers.[1] If efficient risk management options are not available, we would expect to see less competition, which would reduce the choices available to those consumers, and reduce the downwards pressure on prices that is a key outcome of workable competition. The Authority seeks to ensure that the retail electricity market is performing well. If that is not the case, the Authority will act.

This paper sets out the Authority's preliminary findings from the review.

What the evidence told us

Based on the evidence we have received to date and our detailed analysis, our preliminary findings are:

- 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[2] for an OTC contract-based portfolio (baseload hedges and any super-peak hedges, peak hedges or caps) eg, baseload hedges combined with one of battery renting, demand response or retail tariffs. However, these alternative options are only starting to be deployed in the New Zealand market, so may not yet – and perhaps for a few years – be able to discipline the prices of shaped OTC hedge contracts.
- Retailers to date have been able to secure substantial shaped hedge cover through OTC contracts,[3] but the market for shaped cover is neither deep nor liquid. Over a third of the time retailers only receive one offer to requests for shaped hedges.
- The evidence points to fuel or capacity scarcity often being the driver behind the current thin and illiquid market for shaped hedge cover.
- Our analysis indicates that the prices for OTC baseload and peak hedge contracts are likely to be competitive.[4] However, we could not reach the same conclusion for OTC super-peak hedge contract prices as they trade at a substantial unquantified premium over ASX baseload prices adjusted for shape.

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1 While not the focus of this review, we acknowledge that risk management is also an important input for large industrials.

2 That is, provide a similar aggregate level of risk reduction over a range of scenarios.

3 Around half of the OTC contract requests issued during our 14-month assessment period resulted in a trade – refer chapter 5.

4 Based on a comparison with ASX traded baseload prices, which we consider to be an accurate forecast of future prices.

Notwithstanding substantial evidence, key uncertainties remain

In drawing together our preliminary findings we encountered some key uncertainties:[5]

- While the 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.
- Nor could we determine from evidence whether the prices of OTC super-peak hedges were consistent with competitive prices,[6] and whether the increase in OTC super-peak prices (as a percentage of ASX baseload prices) that we observed over the assessment period[7] is justified.

We have considered how to respond to these uncertainties as follows.

Context matters – the sector is changing

There is a substantial change occurring in the sector, as demand increases, and more intermittent generation is built – the market has yet to find its new equilibrium. In relation to risk management specifically, we expect that:

- Supply of traditional hedge contracts – backed by flexible generation – will become tighter as the generation that backs them becomes relatively scarcer (as there is more intermittent generation to firm, but likely less thermal generation in the market).
- There will therefore be a need for all interested parties to invest more in other risk management options, to increase the viable substitutes for these flexible generation-backed hedges.[8]
- Retailers and aggregators will play an important role in developing, supporting and investing in risk management options (eg, activating mass market demand response).

This context – more demand for risk management; relatively less flexible generation to back hedge contracts; viable risk management substitutes still developing – is highly relevant in the short and medium term.[9] That is, all other things being equal, these three aspects will likely impact retail competition, and therefore choice and price for consumers, during the next few years at least. As the sector regulator, the Authority will therefore take an active interest, with a view to:

- Better ensuring the availability of key inputs to retail competition;
- But seeking to avoid overreach, ie, decisions go beyond a proportionate response to present issues, and negatively impact on security of supply, innovation, competition and affordability in the future.

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5 There are other uncertainties noted in the paper as well eg, in chapter 5 when assessing whether the difference between the margins offered by gentailers to commercial and industrial customers on one hand, and non-integrated retailers on the other, was justified.

6 As there is no equivalent forward curve (to the ASX baseload curve) for future shaped contract prices, and we could not reliably determine a competitive value for some of the relevant premiums over baseload (eg, for scarcity) that would logically form part of an OTC super-peak price.

7 1 November 2022 to 31 December 2023.

8 Contact's recent expression of interest for its Stratford battery, and Genesis' Huntly firming options, are good example of parties developing and offering a broader range of flexibility options.

9 It is difficult to predict the exact timeline over which alternative risk management options will develop, but we expect to pay close attention to the relevant market/s for at least the next 5 years.

There is a risk that the Authority should respond to

Regarding the key uncertainties set out above, while the evidence does point to scarcity being a driver, there is also a plausible driver that has competition implications, eg, refusing to supply products on appropriate terms to counterparties who are downstream competitors, indicating that some level of market power could have been in play.

The Authority is charged with promoting competition, reliability and efficiency in the electricity industry for the long-term benefit of consumers. In circumstances where there is a risk that market power in relation to shaped hedge contracts in the short to medium term is impacting the expansion of non-integrated retailers, the onus is on the Authority to respond by:

- Addressing any potential market power issues (amongst other things)
- Promoting competition now and in the future to deliver a better performing retail market ie, more choice for consumers and downward pressure on prices
- While taking account of any impact on reliability and efficiency.

Retail competition brings benefits to consumers, and it will continue to be challenging to operate as a non-integrated retailer as thermal generation exits and intermittent generation becomes more common. Our current view is therefore that:

- It would be prudent to progress on the basis that the availability and pricing of shaped hedges, as part of any risk management portfolio, currently matters and will continue to matter in the medium term.
- It would support retail competition in the short to medium term (ie, at least during this period of change) to deepen and increase the liquidity of OTC hedges, and increase price transparency for shaped products.
- Any strengthening of the market for shaped hedges must not, however, get in the way of all retailers being incentivised to develop and invest in other risk management options (including demand response and tariff options; investment in batteries), and participating in other emerging flexibility initiatives. We expect that both gentailers and non-integrated retailers will contribute to the development of these options, and that development will be faster in a more diverse retail market.

We note in this context the various recent industry initiatives to increase the supply of available flexibility eg, Genesis' Huntly firming options and Contact's syndicated battery. We also note the importance of retaining incentives for all parties to develop demand response for short and longer-term system security and risk management. This is particularly true given modelling indicates these risk management options will be efficient alternatives to shaped hedge contracts as they are further developed, and therefore an important part of retailer risk management portfolios.

The Energy Competition Task Force work is well aligned to these views

The first work package being considered by the Electricity Authority and Commerce Commission's Energy Competition Task Force[10] includes work that specifically relates to the

[10] Energy Competition Task Force | Our projects | Electricity Authority (ea.govt.nz).

availability and pricing of shaped hedges (initiatives 1A and 1B),[11] and two backstops: potential deeper interventions targeted at mitigating gentailer market power concerns (initiatives 1C and 1D).[12]

The two programmes are well aligned. The risk management review will provide an important evidence base for that first Task Force work package, allowing quicker progress and better targeting of that work.[13] Our current view is the Task Force work programme will, to a large extent, take over what we had expected to be the second (policy) phase of the risk management review.

However, one initiative that the Task Force work programme does not respond to directly is gentailer internal transfer prices, and the related disclosure regime. While we do not consider that the internal transfer prices are causing a specific competition harm, as they are not a significant driver of gentailer external pricing or commercial decision making, the disclosure regime is currently a regulatory burden for what seems to be little or no benefit, and the internal transfer prices themselves remain a distraction. Once we have completed consultation on the initial phase of the risk management review, the Authority intends to relook at both internal transfer prices and the related disclosures regime.

We welcome feedback

We welcome feedback on the preliminary findings in this paper. We particularly welcome any further evidence that could address any of the areas of uncertainty that we have set out above.

We will consider stakeholder feedback on this paper early in 2025 and then:

- Recalibrate any Task Force package 1 initiatives if the relevant part of the evidence base (the risk management review findings) changes in any material way
- Confirm as soon as possible whether any further policy responses (outside of the Task Force initiatives) are needed, other than in relation to internal transfer prices and the related disclosures regime.

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11 1A. Consider requiring gentailers to offer firming for Power Purchase Agreements; 1B. Introduce standardised flexibility products.

12 1C. Prepare for virtual disaggregation of the flexible generation base; 1D. Investigate level playing field measures such as non-discrimination rules as a regulatory backstop.

13 The indicative timeframes for delivering the first task Force Work package are set out at Energy Competition Task Force | Our projects | Electricity Authority.

Contents

Chapter 1: Purpose

1. About this review

The Authority is reviewing risk management options for retailers

1.1. Competition in the electricity retail market is critical to achieving better choices and more affordable electricity for consumers. An important enabler of retail competition is the availability of efficient risk management options for electricity retailers. Mass market retail customers are largely on fixed price variable volume contracts, so retailers need risk management options, such as over-the-counter hedge contracts (OTC contracts), to manage the price risk that arises from wholesale spot market volatility.

1.2. The Authority is reviewing risk management options for electricity retailers to:

(a) assess competitive outcomes in relation to OTC contracts, including seeking to identify whether the availability of OTC contracts, in the context of other risk management options, is creating a barrier to entry or expansion in the retail electricity market, and

(b) consider the policy options available to respond to any competition issues identified.

1.3. This paper presents our preliminary findings, for feedback.

Why we're undertaking this review

1.4. The Authority is undertaking this review to better understand the competitive dynamics around risk management options for electricity retailers now and in the future, and to address any issues identified. The review takes place against the backdrop of increasing wholesale market volatility and increasing investment in intermittent generation, both of which will increase demand for efficient risk management options, as well as concerns raised by some non-integrated retailers about the availability and pricing of some forms of risk management.

1.5. This review was announced in December 2023. It follows on from the development of a voluntary OTC Code of Conduct and was announced alongside the findings of the Market Development Advisory Group, which highlighted the importance of risk management and competition in the transition to renewable generation.[1]

Wholesale market volatility will continue

1.6. Wholesale market volatility has materially increased since the Pohokura gas field outage in mid-2018. The Authority's subsequent review of competition in the wholesale market, commenced in March 2021, found that wholesale market prices reflect a sector in transition:[2]

(a) prices between January 2019 to mid-2021 had, at least to some extent, reflected underlying supply and demand conditions, but the Authority noted that

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1 Market Development Advisory Group, Price discovery in a renewables-based electricity system: Final Recommendations Paper, December 2023.

2 Electricity Authority, Decision paper: promoting competition through the transition, May 2023.

generators may have been exercising market power in the wholesale market during that period

(b) from mid-2021 to early 2023, changes in average spot prices had been explained mostly by underlying demand and supply factors

(c) forward prices out to 2027 – while trending downwards – remain above the cost of new supply (as estimated in 2023), reflecting factors such as time to build new generation, investment-impeding uncertainty, and insufficient commercially viable renewable solutions to firm intermittent supply.

1.7. High volatility was most recently observed in August 2024, when price spikes resulting from a shortage of gas combined with low hydro inflows and unfavourable conditions for wind generation saw wholesale electricity prices temporarily increase from around $300/MWh to over $800/MWh.

1.8. Wholesale price volatility is expected to continue. This is because increasing demand combined with the rapid uptake of renewable intermittent generation, like wind and solar generation, will make the electricity system more sensitive to weather effects.

1.9. The impact is two-fold for risk management: increasing wholesale market volatility will drive increased demand for risk management options, as retailers seek to manage their increased risk, while at the same time it may become more difficult to supply OTC contracts and other risk management products that meet retailers' needs, as the generation mix changes. We discuss these dynamics in greater detail in later chapters.

1.10. In December 2023, the Market Development Advisory Group recommended a package of work to increase competition and ensure market participants have access to options to efficiently manage their risks in the transition. Its recommendations included a focus on developing the market for flexibility contracts (or 'shaped products', which are more flexible OTC contracts that provide protection against high spot prices at specific times), increasing demand-side flexibility, and measures to increase competition. This included developing a high level outline of 'virtual disaggregation' of participants assessed as having undue market power to 'put in the drawer' ready for use if other competition measures are not effective.

Non-integrated retailers have raised competition concerns

1.11. The scope of this review has been informed, in part, by competition concerns raised by non-integrated retailers relating to the conduct of the four large generator-retailers or 'gentailers' (Contact, Genesis, Mercury and Meridian).

1.12. New Zealand's electricity market is characterised by high levels of vertical integration, which means that when non-integrated retailers are seeking OTC contracts, they generally deal with the same gentailers that they compete with in the retail market.

1.13. Non-integrated retailers' concerns can be summarised as gentailers:

(a) refusing to supply (or constructively refusing to supply) appropriate OTC contracts (including shaped peak and super-peak products)[3], inhibiting non-integrated retailers' ability to compete in the retail market, and

(b) using their generation profits to cross-subsidise their retail businesses via internal transfer prices (ITPs) and retail pricing, which, alongside their pricing and supply of OTC contracts, is resulting in a margin squeeze whereby non-integrated retailers have insufficient margin to compete against the gentailers' retail operations.

1.14. Underlying these concerns is non-integrated retailers' view that the four gentailers have substantial market power in the wholesale market and their conduct has had the effect of substantially lessening competition in closely related downstream markets.

1.15. During 2023, a number of non-integrated retailers wrote individually to the Commerce Commission requesting an investigation into these concerns under section 36 of the Commerce Act. The Commission undertook enquiries into these complaints during 2023, including engaging with the Authority on the issues raised in the complaints. In December 2023, the Commission announced it had decided not to open an investigation at that time, noting the Authority's intention to undertake a review into retailers' risk management in 2024. It considered the most effective use of the Commission's competition resources was to provide staff support to the Authority's review. Senior Commission staff subsequently provided active support to this review project.

1.16. More recently, these non-integrated retailers have sought Code amendments to apply corporate separation and arm's-length rules to the gentailers to address (amongst other things) their retail electricity market level playing field concerns.

1.17. These concerns have been considered as part of this review where they relate to the availability of efficient risk management options. As we note below, a key component of our analysis is the extent to which market structure and the dual role of gentailers is impacting on risk management, and whether this is creating barriers to retail competition.

1.18. This review does not specifically focus on retail pricing. We have not, therefore, made any preliminary findings relating to whether there is a margin squeeze. Our work on the pricing of OTC contracts offered by gentailers is, however, a core input into any margin squeeze analysis. The Authority is already looking to obtain critical information about retail pricing through its retail data project.

1.19. For completeness we note that the availability and pricing of hedge contracts, and how that impacts retail competition, was previously considered in 2018/19, by the Government-initiated Electricity Price Review.[4]

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3 Peak hedges provide risk management cover throughout the day; super-peak hedges provide more targeted risk management cover during the morning and evening peaks – refer to the Glossary for more detail.

4 Electricity Price Review | Ministry of Business, Innovation & Employment (mbie.govt.nz).

1.20. In its final report in 2019 the Electricity Price Review's conclusions included that the hedge contract market was not working effectively, limiting the ability of non-integrated retailers to manage price risk and undermining confidence in the market.

1.21. The Electricity Price Review recommended a range of interventions in response, including:

(a) Mandatory market-making for ASX traded futures contracts

(b) A review of wholesale electricity market information disclosure rules

(c) Disclosure of gentailer internal transfer pricing

(d) Periodic comparisons of wholesale contract prices with new-generation costs.

1.22. The Authority implemented these changes, and has since made further improvements.[5] However, non-integrated retailers argue that the overall response has been ineffective or poorly implemented, and that the availability of appropriately priced hedge contracts is one of the core reasons why their growth has plateaued.

Scope of this review

1.23. This review seeks to:

(a) **establish key context, both in terms of workable retail electricity market competition**, including the roles of different retailers in the market, and **the impact of the transition to renewable generation** (chapters 2, 3 and 6)

(b) **assess whether retailers have access to efficient risk management options**, which includes an assessment of:

(i) the different options available to retailers now to manage risk (chapter 4)

(ii) the availability and pricing of OTC contracts (chapter 5)

(iii) how risk management for retailers is expected to change in future (chapter 6)

(iv) whether (alleged) gentailer market power is impacting on risk management (chapter 7)

(c) **consider what insights we can draw from this analysis to guide any interventions**, in the short and long term, to address preliminary findings related to (b) above (chapter 8).

1.24. The Authority initially intended to conduct this review in two sequential phases (with phase 1 – investigation – focusing on items (a) and (b) and phase 2 – policy response – focusing on item (c)). Considering recent developments, including the August 2024 price spikes and the establishment of the Energy Competition Task Force (discussed below), we have decided to include aspects of phase 2 in this paper.

[5] Eg, recent changes to hedge disclosure obligations; introduction of a commercial market maker.

Our approach to this review

1.25. The Authority's main statutory objective is to promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.[6] This forms the touchstone of this review.

1.26. Consistent with this, our overarching outcome (or desired future state) is that risk management options (in aggregate) are accessible and priced efficiently, in which case they should promote workable competition in the retail electricity market. This promotes the long-term benefit of consumers through lower prices and better choices.

1.27. This overarching outcome has guided our approach to examining the evidence and making the preliminary findings in this review.

1.28. While this review is focused on risk management options available to retailers, the preliminary findings and policy options explored in this paper will be relevant to large commercial and industrial consumers that similarly rely on risk management options to manage their wholesale spot price risk, and also of interest to non-integrated generators.

Consideration of the Commerce Act 1986

1.29. This review does not make any findings (preliminary or otherwise) relating to any provisions of the Commerce Act 1986, including section 36, which deals with misuse of market power. In particular, this review does not assess the complaints submitted by the non-integrated retailers against section 36 of the Commerce Act. Such matters are within the jurisdiction of the Commerce Commission.

1.30. Our focus in this review is different to – and broader than – the misuse of market power test under the Commerce Act. However, given the similarities between the Authority's main objective and our overarching outcome of this review, and the purpose of the Commerce Act (which is to promote competition in markets for the long-term benefit of consumers within New Zealand),[7] the Authority has drawn on the experience of Commerce Commission staff in investigating and enforcing Commerce Act provisions to better understand the extent to which the information examined in this review reveals a competition problem.

1.31. In particular, we have:

(a) considered appropriate approaches to how markets are defined for the purposes of the Commerce Act in consultation with Commerce Commission staff, and analysed information with reference to (although not completely following) that framework, to better understand the extent to which OTC contracts can be substituted by other risk management options, which has a material impact on whether their availability could be a barrier to retail competition

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6 Section 15 of the Electricity Industry Act 2010. The Authority's additional objective, which is to protect the interests of domestic consumers and small business consumers in relation to the supply of electricity to those consumers, only applies to the Authority's activities in relation to the dealings of industry participants with domestic consumers and small business consumers: section 15(2)–(3) of the Act. It is not engaged in this review, which is focused on dealings between participants.

7 Commerce Act 1986, s 1A.

(b) taken account of the expectations that section 36 of the Commerce Act sets for use of market power generally

(c) made some observations regarding market power using the Commerce Act framework as a reference point which, in the context of the market definition, impacts how we assess gentailer behaviour, and the nature of any policy response, and

(d) considered whether any guidance can be drawn from section 36 cases.

1.32. For the avoidance of doubt, while we have used the Commerce Act framework as a reference/starting point, we have not conducted a complete section 36 analysis.

Alignment with the Energy Competition Task Force and other work

1.33. The Authority and the Commerce Commission jointly established the Energy Competition Task Force, with the Ministry of Business, Innovation and Employment as an observer, in response to the August 2024 spike in wholesale prices. The Task Force is considering ways to improve the performance of the electricity market including by enabling new generators and independent retailers to enter, and better compete, in the market.

1.34. The Task Force is considering four policy options as part of 'Package 1', which relate to enabling new generators and new retailers to enter and better compete in the market. They are:

(a) consider requiring gentailers to offer firming for Power Purchase Agreements

(b) introduce standardised flexibility products

(c) prepare for virtual disaggregation of the flexible generation base, as a regulatory backstop

(d) investigate level playing measures such as non-discrimination rules, as a regulatory backstop.

1.35. The preliminary findings in this review and the submissions on them will feed into the development of these options by the Task Force.

Information considered as part of this review

1.36. As part of this review the Authority has:

(a) considered concerns first raised by non-integrated retailers in 2023

(b) requested and received a substantial amount of information from non-integrated retailers and gentailers

(c) sought and received feedback from other participants to ensure a range of perspectives have been taken into account, including independent generators, major users and brokers.

1.37. We welcome further input on both our initial findings and views on policy options discussed in this report.

How to make a submission

1.38. The Authority's preference is to receive submissions in Microsoft Word to rmr@ea.govt.nz with "Submission" in the subject line by 5pm on Wednesday 18

December 2024. We welcome submissions on any aspect of the paper, but have set out some guiding questions in Appendix D.

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

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

1.41. 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).

1.42. 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.

1.43. 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.

ELECTRICITY AUTHORITY
TE MANA HIKO

Chapter 2: Electricity retail market competition context

Contents

1. Purpose

1.1. This chapter considers aspects of retail electricity market competition, to provide relevant context to the risk management review. That includes:

(a) Recapping both:

i. the functions of an electricity retailer, and

ii. the composition of the retail electricity market, including how that has changed in the past ten years

(b) Considering what different groups of retailers (large vs medium) bring in terms of innovation to the retail market, as a high-level proxy for how much value those groups bring to consumers through competition.

1.2. This high-level assessment of value is an important contextual factor for this review. It is medium size (and some smaller) non-integrated retailers that are largely seeking better access to shaped hedges supplied by gentailers. While the Authority conceptually supports all competition, if the evidence suggests that there is an access concern, the Authority will then consider the costs and benefits of a policy intervention. The benefits will largely come from the impact the intervention would likely have on retail market competition. So any indicators of the value medium (and small) retailers bring to that competition are relevant.

1.3. This section does not seek to comprehensively survey retail competition in New Zealand – rather, it seeks to draw specific insights that will help shape any policy response to risk management issues.

2. The role and functions of electricity retailers in New Zealand

2.1. At the most fundamental level, electricity retailing involves the sale of electricity purchased from the wholesale market to residential, commercial, and industrial customers. Mandatory functions of retailers are:

(a) acting as the single (or primary) interface between electricity consumers and the electricity industry

(b) providing a billing function that ultimately recovers the cost of electricity (including generation, transmission, distribution and metering costs) from consumers

(c) managing price risk that arises from wholesale spot market volatility on behalf of its customers. As described earlier in this paper, mass market retail customers are largely on fixed price variable volume (FPVV) contracts.[1] The retailer manages the interface between this retail pricing and the volatile wholesale electricity price, and can share some (or occasionally all) of this price risk with consumers

(d) providing customer care, at least to the extent required by regulation, eg, the set of expectations set out in the Consumer Care Guidelines, which the

[1] Not all consumers are on FPVV contracts. Some retailers, like Flick Electric, have offered plans that pass-through wholesale spot price risk.

Authority is currently proposing to mandate in the Code,[2] and existing obligations under the Code to:

i. provide information about the electricity plan comparison platform (currently Powerswitch) and the disputes service (Utilities Disputes Ltd)

ii. provide consumers with information about their electricity consumption

iii. operate the customer compensation scheme under Subpart 4 of Part 9.

2.2. Retailers are also well positioned to go beyond these basic functions and provide more to consumers, including:

(a) Offering a range of pricing options that provide consumers with greater choice in managing their electricity costs, as well as incentivising more efficient system use. Many retailers offer a range of tariff structures, which allows consumers opportunities to limit their financial exposure or to take on some level of risk.

(b) Offering tailored plans or services for particular consumer groups, including those in hardship (social retailing).

(c) Providing other electricity adjacent services, which again better allow consumer to control their electricity use and cost, such as aggregation or demand response (which can also support risk management), selling or financing solar assets and batteries, and providing energy efficiency services. Retailers are not the only parties that can offer these adjacent services, but likely have an important role to play, at least as we transition to a more technology-enabled environment, in developing the flexibility services market.

(d) Bundling electricity with other services, such as broadband, phone or gas. Bundling is common across many larger retailers.

(e) Increased customer service and convenience, going beyond the minimum regulatory expectations for customer care.

2.3. This review is focused particularly on the risk management function of retailers. For mass market customers particularly, we consider this to be one of their core roles. It is therefore important for appropriate risk management products to be available to them, but also for retailers to demonstrate their own ability to develop an effective risk management portfolio, as this is one of the areas in which they compete.

2.4. The review is also concerned with the related retail functions of offering a range of retail tariffs and adjacent services to help consumers to manage their use of and expenditure on electricity (as well as potentially reducing long-term system costs by reducing peaks, and the network and generation expenditure that they drive). These are part of the core risk management options available to retailers in addition to hedge contracts, will become increasingly important over time (as explained later in the paper), and are an area where they can differentiate themselves from other retailers.

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[2] See: Consumer Care Guidelines | Our projects | Electricity Authority (ea.govt.nz).

3. Composition of the electricity retail market

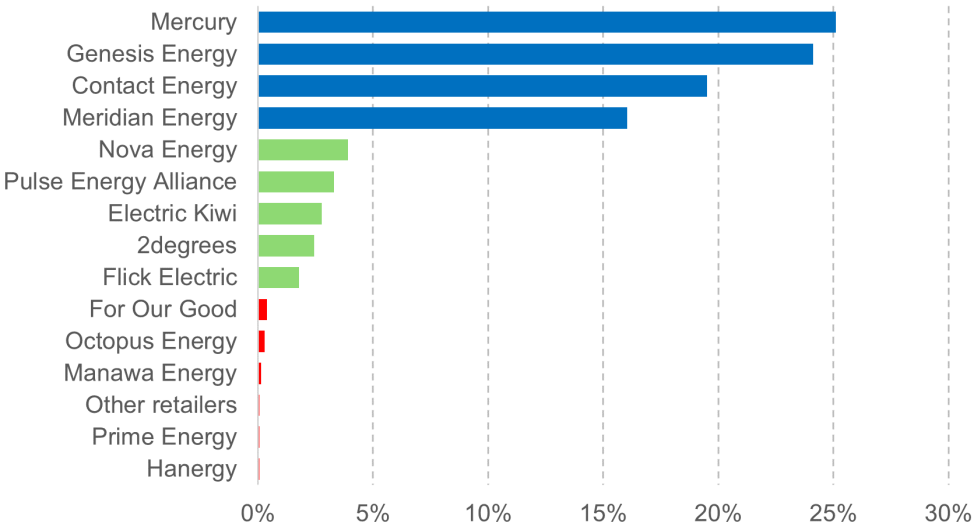
3.1. New Zealand's electricity retailers, based on market share, break down into three broad groups:

(a) Large retailers in blue (100,000+ ICPs)

(b) Medium retailers in green (10,000 – 99,999 ICPs)

(c) Small retailers in red (less than 10,000 ICPs). Other retailers are those with less than 1,000 ICPs.

Figure 1: Market share by ICP
as at 31 August 2024



Large (100,000+ ICPs)

3.2. This group is comprised of four large, vertically integrated generator retailers (gentailers) – Mercury, Genesis, Contact and Meridian. Most of New Zealand's large-scale flexible generation (such as the large hydro stations) is owned by these gentailers and was built under Government ownership.

3.3. The integrated nature of these large retailers provides them with a natural risk management hedge (mitigating the price risk from the wholesale spot market through their own generation – discussed later in this paper).

Medium (10,000-99,999 ICPs)

3.4. This group includes Nova, Pulse, Electric Kiwi, 2degrees, and Flick. They have a range of backgrounds (business models, length of time in the electricity sector), and rely on a range of hedging strategies to manage their wholesale spot price risk (see chapter 4). We note that:

(a) Two of these medium retailers are also vertically integrated – Nova and more recently Pulse

(b) Both 2degrees and Octopus (which is currently a smaller retailer in New Zealand, but large internationally) have a strong track record of successful

market entry (in New Zealand telecommunications and overseas electricity markets respectively)

(c) None of these medium retailers are new entrants – all have been in the market for at least eight years (albeit with some ownership changes).

Small (less than 10,000 ICPs)

3.5. Small retailers have the highest entry and exit statistics, reflecting the ease of entry into the New Zealand electricity market. All recent market entrants are currently small retailers.

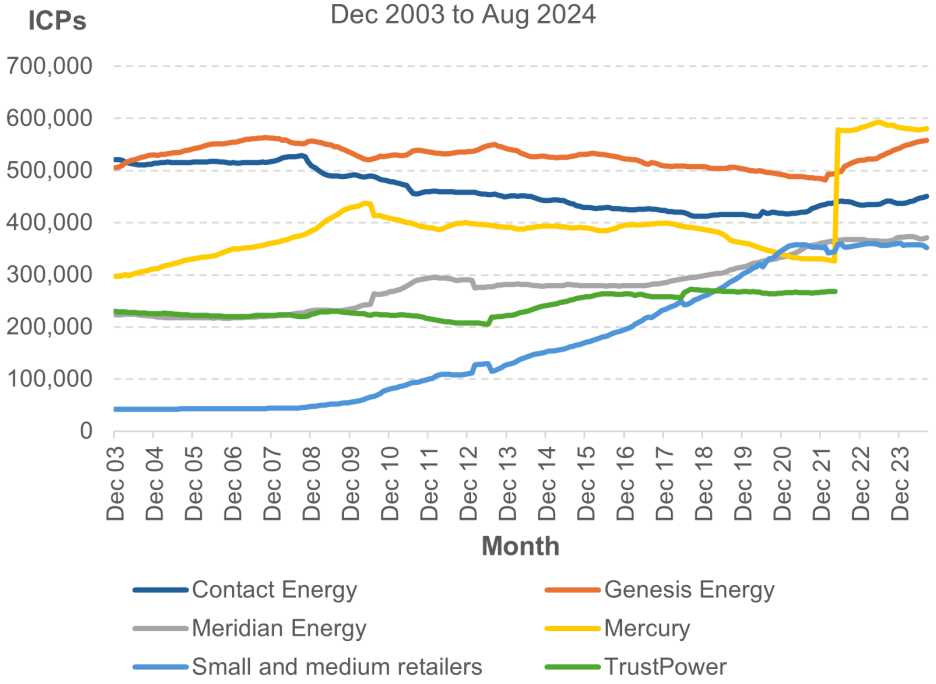
3.6. Small retailers are understandably diverse, including their target markets, business models and growth strategies.

Market share of medium and small retailers has plateaued since 2021

3.7. As has been well traversed in the sector, market share of small and medium sized retailers has plateaued after a sustained period of growth, as set out in Figure 2:[3]

Figure 2: Retail market share by ICP

Dec 2003 to Aug 2024



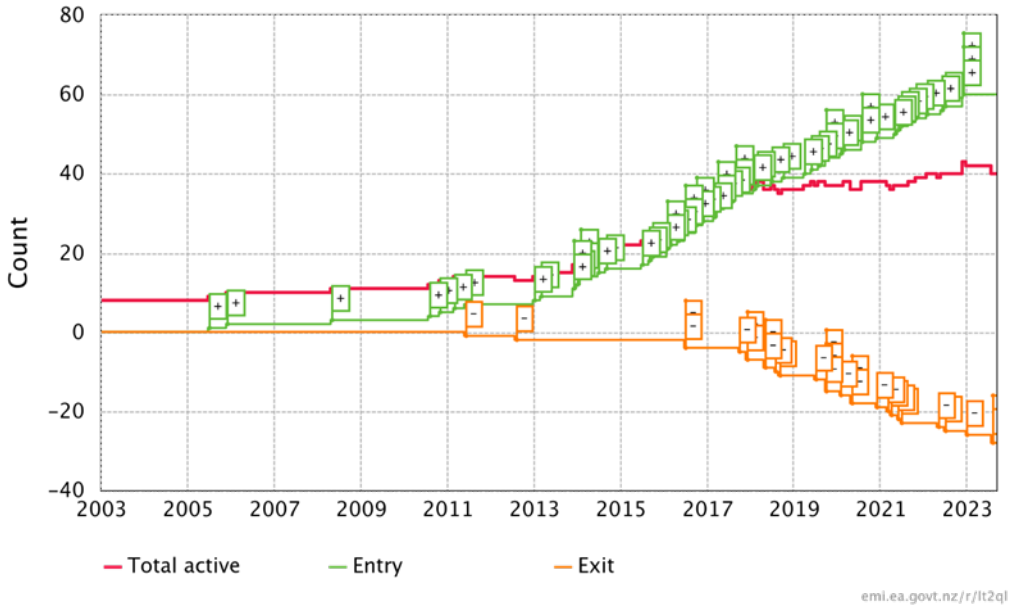
3.8. While the number of retailers entering the market has increased since 2011, the number of retailers exiting the market since 2018 has also increased, as indicated below in Fig.4.

3.9. As a result, the number of active retailers has not changed significantly over the last five years.

Figure 3: Retailer entry and exit

[3] The sudden increase observed in Mercury's market share in Fig. 3 is due to its acquisition of Trustpower's retail ICPs in mid-2022.

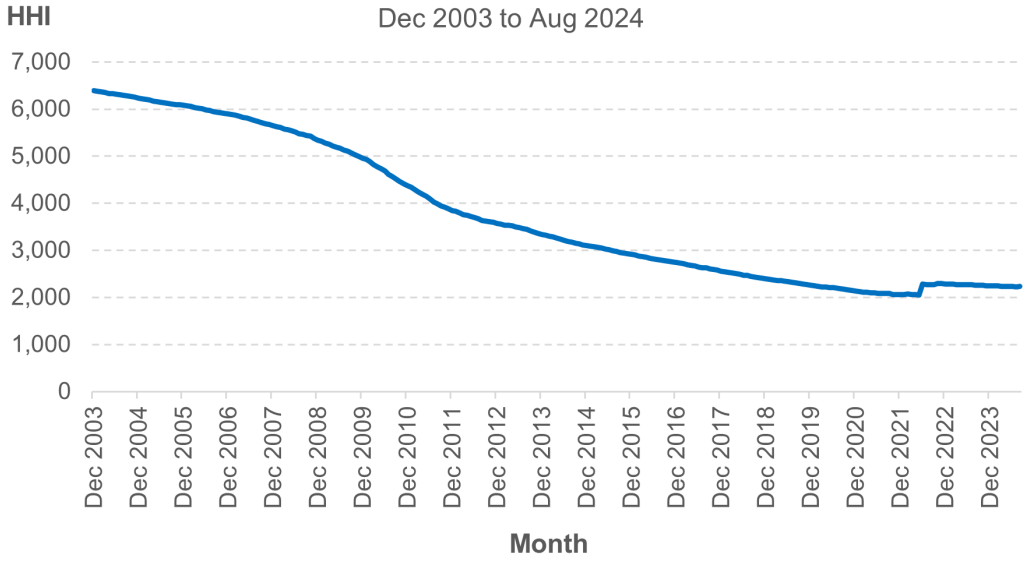
Jan 2004 to Aug 2024



3.10. Retail market concentration has also decreased over time, but has been relatively constant since the transfer of Trustpower's retail ICPs to Mercury in mid-2022, as below in Fig.4:[4]

Figure 4: Retail market concentration: Herfindal-Hirschman index

Dec 2003 to Aug 2024



3.11. While it likely masks some complexities, this simple market composition analysis indicates:

[4] The Herfindahl-Hirschman Index measures the size of companies relative to the size of the industry they are in as an indicator of the amount of competition in the industry. A lower HHI generally indicates an increase in competition.

(a) There do not appear to be material barriers to entry into the retail electricity market

(b) Barriers to expansion by new entrants are worth considering (from a retail competition perspective). We would normally expect to see small to medium retailers vigorously competing to grow their share, as occurred until 2020, including through innovation, agility and/or highly competitive pricing. That competitive impact appears to have stalled. While that may not signal any competition or risk management problem, it merits investigation, especially when a group of small to medium retailers are pointing to a specific issue (as they see it) as a barrier to expansion.

4. Using market innovation as a method for assessing the value of large vs medium retailers to retail competition

4.1. Workably competitive markets can bring significant benefits to consumers over the long term by being conducive to entry and expansion by innovative suppliers and to efficient investment.[5] In essence, the competitive threat of new entrants can incentivise innovation and improve value for consumers.[6]

4.2. To understand how consumers have benefited from the level of competition in the New Zealand retail electricity market, we have examined innovations in the retail market over the last 10 years.[7] We are considering innovation in the retail market because:

(a) innovation is core to the long-term dynamic efficiency benefits that competition is meant to bring to consumers

(b) it is a useful lens – and can be broken down into different innovation types to better indicate the impact that different groups of retailers are having on competition

(c) we have heard various informal assertions that newer entrants are the innovators, and wanted to test that view.

Methodology

4.3. We undertook an analysis of innovations that have occurred in the electricity retail market over the past ten years (from 2014 to 2024).

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5 Electricity Authority, Interpretation of the Authority's statutory objective, 14 February 2011 at 2.2.1.

6 Australian Competition and Consumer Commission, Inquiry into the National Electricity Market, December 2023, pg. 22

7 This work could have used several lenses in considering the contribution of different types of retailers to retail competition. One that could have been applied is through the lens of retail price (aka who is driving price competition). However, this is complex when taking account of segmenting and sub-brands, and even more so given the anti-competitive pricing allegation ('margin squeeze') that is currently being analysed.

4.4. We used a broad definition of innovation – as a process that marries a problem with a solution to create impact[8] – and defined it specifically for the New Zealand electricity retail market as something that happens within the New Zealand market for the first time.[9]

4.5. We categorised different forms of innovation according to:

(a) context and magnitude of innovation. That is:

i. Incremental innovation: existing product / service; existing market.

ii. Disruptive innovation: new product / service; existing market

iii. Architectural innovation: existing product / service; new market

iv. Radical innovation: new product / service; new market[10]

(b) type of innovation (product and product performance, technology, business model, organisational, process, marketing / sales / channel, network, customer engagement, retention, configuration, offering, experience).

Assessment

4.6. We identified and considered around 80 innovations that had been introduced in the electricity retail market over the past 10 years.[11]

4.7. In our initial assessment of innovations over the last 10 years by volume, it appears that the gentailers (large retailers) have led the majority of these innovations.

4.8. However, this picture changed when we referenced this against our categorisation of innovation magnitude, type, and impact. Particularly:

(a) When we segmented the 10 years of innovations by context and magnitude we found that most were 'incremental', rather than 'architectural' or 'disruptive'.

(b) When we segmented the innovations by type, we found that most were customer service / marketing / channel focused, rather than network or technology focused.

(c) Medium retailers are overrepresented (compared to their market share) in the disruptive, architectural and radical innovations.

4.9. Table 1 includes what we consider to be some significant 'shift' innovations over the last 10 years.

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8 See for example the OECD's Oslo Manual which provides guidelines for collecting and interpreting data on innovation: Oslo Manual 2018 | OECD.

9 As such, even if an electricity retail product, service, or process existed in every other market, but was not present in New Zealand, its introduction to this market would be considered 'innovation'. Likewise: anything that changed existing endeavours in this market in a way that was new and improved would fall under the definition.

10 We note that there is no one standard way to categorise innovation, but see for example The Role Of Innovating In Competitive Success And How To Do It (forbes.com).

11 Refer Appendix C. We note that the total quantum of these innovations, and the way we have categorised them, is according to a particular approach. We selected ten years because it provided a long sample from a period in which the current medium sized retailers had been present for the majority of the time (at least 8 years).

Table 1: Significant innovations over the last 10 years

Year introduced	Innovation example	Context and magnitude of innovation	Innovation type	Type of retailer that introduced it
2014	Usage monitoring	Architectural	Technology	Gentailer
2014	Solar buy-back	Architectural	Network	Gentailer
2014	First app	Architectural	Marketing / sales / new channel	Gentailer
2015	Mass market customer access to spot price	Architectural	Network	Non-integrated retailer
2015	“Free hour of power”	Disruptive	Customer engagement / retention	Non-integrated retailer
2016	Time of Use charging	Disruptive	Customer engagement / retention	Non-integrated retailer
2019	Internet of things connectivity	Disruptive	Network	Gentailer
2020	First 'roaming' EV charging	Disruptive	Network	Gentailer
2022	Virtual solar	Radical	Technology / network	Non-integrated retailer

Methodology limitations and observations

4.10. We note that:

(a) the table of innovations above is to provide insights and examples, but there are likely to be additional examples that were not accessible to us or in the public domain

(b) our categorisation process relies on judgement, and we invite feedback on how these categories have been applied

(c) our assessment of the type of retailer that first introduced the innovation is based upon the best available public information – we welcome feedback on this assessment.

4.11. Our overall assessment of the impact of innovations (underlying the table of shift innovations above) is not just about the innovations themselves, but also how actively the retailer pursues them. The innovation will have a different impact if, for example, a retailer passively offers a time of use tariff versus if it actively moves its customers to that tariff.

What might New Zealand be missing out on?

4.12. Whilst the 80 innovations from the past decade may sound productive, innovation in the New Zealand electricity retail sector may still have potential to be more impactful.

4.13. In our analysis, we also looked at innovations in other sectors in New Zealand such as retail and banking. In terms of general service innovations, such as online

customer services, the use of apps, and live chat, the electricity retail sector seems generally to follow, rather than lead.[12]

4.14. Innovation in electricity retail markets in comparable countries also seems to be more advanced or disruptive.[13] A number of innovations seen overseas have not yet arrived in New Zealand at scale. We set out three examples of innovations from other markets below. While they are not conceptually that different from some of the current offers or trials in the New Zealand market (eg, load control, time variant pricing), they provide more options for consumers, a more integrated service, and a more granular (user friendly) ability to respond to market pricing:

(a) David Energy, a New York-based company, provides an integrated service to consumers to reduce electricity costs and promote greener energy. It uses an automated demand response platform to control consumers' devices and electricity supply (eg, EVs, smart appliances, home batteries and solar), and connect demand and supply in real time.[14]

(b) Tibber in Sweden is a digital energy company that enables greater consumer choice to help lower electricity consumption and bills. This includes better visibility of electricity pricing and household consumption (app based, including notifications and analytics), smart charging of appliances (EVs), selling smart devices. Tibber also has a digital platform for purchasing electricity, which it passes through to its customers at no margin...[15]

(c) Octopus Energy in the UK offers a pricing option for EV charging ('Plunge Pricing') which allows electric vehicle owners to (among other things) benefit from low wholesale prices when renewable generation is high and demand is low. Customers are incentivised to take excess energy off the grid at these times including through public charging.[16]

4.15. Overall, innovation in the New Zealand electricity retail sector seems to be more incremental, at a customer-facing level. There appears to be less network, technology, or whole-of-system innovation at widespread scale as seen in other markets.

4.16. The regulatory context has an important role to play. Government and regulators in other countries with greater innovation have at times applied more active tools to promote this sort of innovation than in New Zealand, including clearly stated approaches and goals, regulatory sandboxes, and innovation funds.[17]

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12 By way of New Zealand examples, online banking was first offered in 1997; and the first supermarket shopping app was launched in 2012.

13 We looked at Australia, the EU, the UK, and the US.

14 David Energy | Smart electricity for home & business | Powering what's next

15 Forget everything you know about energy companies ⚡ Tibber

16 Octopus in the UK offers a range of innovative products, including Powerloop, an EV leasing bundle that allows consumers to power their homes with their cars during peak energy periods, and Intelligent Octopus Go, which coordinate assets (such as connected EVs), ensuring that customers only charge at the cheapest, greenest times, taking pressure off the grid and reducing consumer costs.

17 See for example the Energy Innovation Programme previously funded by the UK Department for Business, Energy and Industrial Strategy: Energy Innovation - GOV.UK (www.gov.uk).

4.17. The Authority wants to see more innovation, and we are looking to support this through initiatives like the recently announced Power Innovation Pathway initiative.[18]. However, it remains our broad view that the market should provide an appropriate platform for efficient innovators looking to scale up.

Insights from retail competition that impact the risk management review

4.18. Our high level assessment of innovation indicates that medium size (and some smaller) non-integrated retailers contribute to innovation in a significant way, and likely in a greater proportion to their market share.

4.19. Retail electricity market innovation benefits consumers – providing more choice, better service and likely reducing costs over time. Our assessment of retail market innovation over the last 10 years suggests that there will be more innovation, and therefore more benefit to consumers, if competition in the retail market remains diverse, which includes competition from a range of non-integrated retailers.

4.20. This is not to downplay the benefits that gentailer innovation can bring, noting particularly the recent increase in gentailer focus on demand response and risk management offerings.[19] But we are satisfied that at a general level other retailers, apart from the gentailers, have an innovation role to play, including by keeping the pressure on gentailers to innovate.

4.21. In the context of this review, it follows from this insight that significant benefits are likely to come from an effective policy response to any issues we identify with the availability and pricing of risk management options.

4.22. On the flipside though it is important to reiterate that risk management options are not just something provided by gentailers. They are also appropriately invested in (time, money, effort) by non-integrated retailers – to best align with their business needs, to best ensure that development of options (other than hedge contracts backed by flexible generation) is efficient and innovative. As noted later in this paper we expect investment in other risk management options to become more important with time. So any policy intervention should preserve the incentives for retailers to invest themselves, particularly in mass market demand response, tariff innovation, and batteries (or at least supporting battery investment and renting by others).

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18 Power Innovation Pathway | Electricity Authority (ea.govt.nz)

19 Eg, Contact's hot water control trial via their Hot Water Sorter product. Gentailer initiatives are discussed in chapter 4.

ELECTRICITY AUTHORITY
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Chapter 3: Why does the electricity industry need risk management products?

Contents

1. Purpose

1.1. This chapter sets out the market context within which this review is grounded. It discusses the current and expected future market conditions that impact on risk management product demand, availability, and prices.

2. Electricity spot prices are very volatile

2.1. In New Zealand, the majority of electricity generated must be sold in the wholesale spot market.[1] It cannot be sold directly (ie, via bilateral physical supply) to electricity retailers or consumers. This is why the New Zealand wholesale market is often referred to as a gross pool. Retailers then purchase the electricity they need to supply their consumers from this gross pool.

2.2. Prices in the spot market for electricity are set every half-hour, based on supply and demand during that half hour. Due to the largely non-storable nature of electricity[2] (demand must always meet supply), these spot prices are inherently volatile. This spot price volatility provides price signals to the market reflecting supply and demand needs. These price signals are important for efficient dispatch of generation to meet demand, and in the longer-term to provide signals for investment in new generation.

2.3. However, the volatility inherent in the spot price presents a substantial price/cost risk to market participants, ie, the sellers (generators) of electricity can be exposed to low prices; the buyers (retailers and other large customers) can be exposed to high prices.

3. And spot price volatility is increasing

3.1. Since 2018 electricity spot prices in New Zealand have been higher and more volatile than in previous years (see Figure 1). The Authority's trading conduct analysis indicates that spot prices have tended to reflect underlying conditions since the introduction of the new trading conduct rule in mid-2021. This indicates that these spot prices reflect competitive outcomes.[3] The higher and more volatile spot prices reflect:

(a) the tightening supply/demand peak capacity situation (with some impediments delaying new investment entering at pace)

(b) thermal fuel supply uncertainty (with associated higher prices for gas and coal)

(c) an increasing proportion of intermittent generation.

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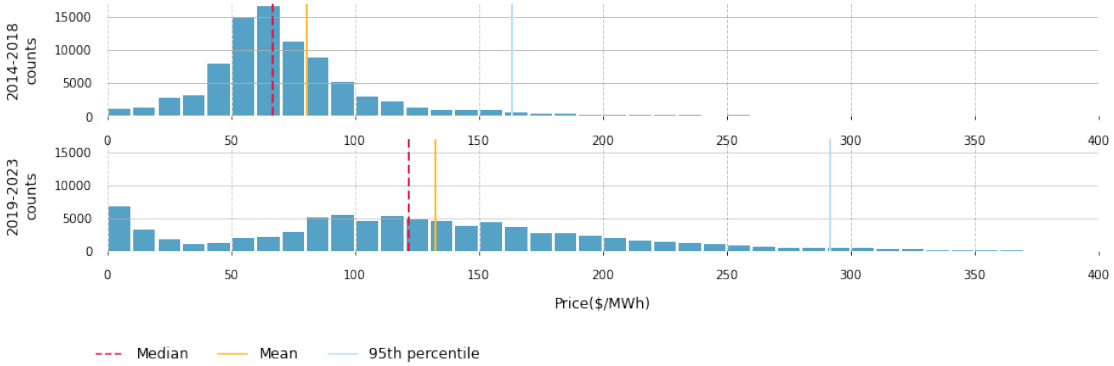
1 The exception is generation that is less than 30MW.

2 The exception being batteries, which need to charge by consuming electricity. Large-scale batteries started entering the New Zealand market this year.

3 Trading conduct reports can be found here: https://www.ea.govt.nz/industry/monitoring/. Prior to the implementation of the current trading conduct rule, the wholesale market review of competition in the spot market concluded that market power may at times have had an impact on prices in the spot market.

3.2. Figure 1 shows the (half-hourly) spot price distributions for the period 2014-2018 compared to those for 2019-2023. In the later years, the tail at the top end of the distribution is much longer – that is, sometimes there have been some very high prices. There is also a higher tail at the bottom end of the distribution, showing a higher occurrence of very low prices compared to previous years. That is, the distribution of both high and low prices (ie, price volatility) has increased compared to 2014-2018.

Figure 1: Spot price distributions



3.3. As the economy decarbonises and the electricity market moves towards 100% renewables, we expect spot price volatility to keep increasing.[4] This is in large part due to the expected physical changes in the market – in particular, how demand will be met when intermittent generation can't run.

3.4. Figure 2 shows historical and forecast flexible generation (generation that can flex to meet demand at short notice) and baseload generation.[5] In Figure 2, we have counted all batteries, hydro, and thermal generation as flexible, although there are constraints on the flexibility of each at any given point in time. The 50th and 95th percentile lines plot this flexible and baseload generation assuming the volume of outages for the flexible generation is at the 50th and 95th percentiles historically (ie, the average number of outages historically, or a very high number of outages by historical standards).

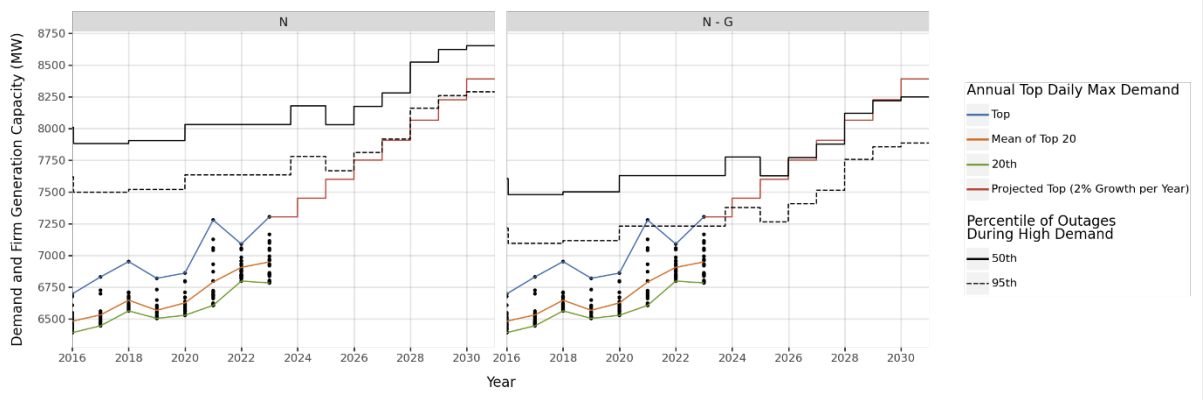
3.5. Since 2018 the amount of generation available (if there were a high number of outages by historical standards) to meet peak demand has started to creep below the top peak demand quantities for N-G (ie, less supply was available than demand taking into account supply needed for the sudden loss of one generator). If peak demand grows at around 2% per year, it will be at a similar level – or above by 2030 - to the amount of flexible and baseload generation available (when keeping enough in reserve for the loss of the largest generator), even with an average number of outages. This highlights one of the issues that the industry is grappling with – how

4 MDAG modelling supports this view, see https://www.ea.govt.nz/projects/all/pricing-in-a-renewables-based-electricity-system/consultation/price-discovery-under-100-renewable-electricity-supply/

5 Baseload generation is geothermal generation and co-generation, operating at their 50th percentile during peak periods (ie, average historical output). Forecast geothermal generation and co-generation is all committed and actively pursued projects in the pipeline (again operating at the historical 50th percentile during peak periods). Forecast flexible generation includes all committed and actively pursued batteries, hydro, and thermal generation that is in the pipeline.

to meet peak demand in winter when it's not windy, with a declining proportion of flexible generation.

Figure 2: Forecast flexible and baseload generation capacity margins



4. Retailers manage spot price risk for consumers

4.1. Retailers purchase electricity on the volatile spot market and sell electricity at (usually) a fixed price. A core function of retailers is to manage the risk that this entails, so the consumer doesn't have to.

4.2. Non-integrated retailers need to manage their costs of supplying electricity to consumers. This is why they need to hedge their risk – ie, to protect against financial loss. Retailers have both price and volume risk:

(a) Price risk is the risk of facing high prices for purchasing electricity (price volatility and uncertainty) – potentially much higher than the fixed prices at which they have agreed to sell it.

(b) Volume risk is the risk that the volume sold to their customers (traditionally on fixed price variable volume (FPVV) contracts) is higher than forecast (unpredictability in forecast load). This includes short-term uncertainty for a given customer base (eg weather related demand changes, social changes like school holidays), and changes in the size of the customer base in the mid to long term (caused by churn in customer numbers due to internal or external factors, such as customers responding to price and non-price competition between retailers, to alternative forms of energy such as gas and solar power, and to incentives for demand response).

4.3. Regardless of how retailers hedge their expected load, they will inevitably be short or long given demand uncertainty. This is especially true for most non-integrated retailers in the New Zealand market who mainly have residential customers. Any corresponding adjustment on the spot market will be made at volatile half-hourly prices, whereas retail prices are generally set for a longer time period. This asymmetry of prices (spot vs retail) combined with demand variability can generate very high losses for retailers who are not efficiently hedged.[6]

[6] https://eprints.lse.ac.uk/82976/1/Porcher_Hedging%20strategies_2017.pdf

5. Risk management can be thought of as a form of insurance

5.1. Risk management is an integral part of all businesses. Companies maximise profits within constraints, and risks are one group of constraints. However, due to the non-storable nature of electricity, electricity retailers are exposed to joint volume and price risk (in other commodity markets, retailers are more able to rely on storage to manage demand/volume uncertainty). That is, risk management is a core function for electricity retailers in a manner different to many other businesses.

5.2. Risks can be dealt with in three ways:

(a) Tolerated and kept

(b) Transferred wholly or partly to another party

(c) Terminating or constraining the activity giving rise to the risk.

5.3. The first option above in the context of the electricity market would be selling or purchasing solely on the spot market, and tolerating all price and volume volatility that arises. That is, not using any risk management products to reduce the price and volume volatility. In this case, the retailer would need a sufficient balance sheet to see out the periods when they make a loss.

5.4. The second option above normally means an extra cost – this is why risk management can be thought of as a form of insurance. The party transferring the risk pays a "risk premium" to offload that risk. To buy a risk management product that completely eliminates all risks would likely mean the "insurance premium" would be prohibitively high. The challenge is therefore to find an efficient solution that provides for an acceptable level of risk at acceptable costs.[7]

5.5. The third option includes such activities as investing in generation or batteries (constraining how much load you have exposed to the spot price), demand response (constraining demand at times of risk exposure) or pass through of spot prices to customers (ie, effectively constraining the activity at the customer end that gives rise to the risk).

6. Increased spot price volatility means risk management is becoming more expensive

6.1. The increasing scarcity in the market (which is being reflected in increasing spot price volatility as shown in Figure 1) also impacts risk management. Scarcity impacts both the supply and demand for risk management products.

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[7] Costs include both risk premia and internal administrative costs of managing a complex hedge portfolio. See: https://www.acer.europa.eu/sites/default/files/documents/en/Electricity/MARKET-CODES/CAPACITY-ALLOCATION-AND-CONGESTION-MANAGEMENT/Documents/200406%20DNV%20GL%20report_final.pdf

There is increasing scarcity of capacity available to under-write shaped risk management products

6.2. On the supply side, there is increasing scarcity of capacity available to under-write shaped contracts. As more intermittent generation enters the market, this means a greater proportion of generation requires firming to meet electricity demand. This firming can be met through flexible generation or demand response. As demand response capacity is still developing, this means the current stock of flexible generation (plus a small amount of new investment) is increasingly needed to fill the gaps when it is calm or cloudy. As much of this flexible generation is hydro generation, low hydro storage can also result in even less capacity from this flexible generation to meet these gaps. A similar situation occurs for thermal generators when gas supply becomes constrained.

6.3. Additionally, it is this flexible generation or demand response, alongside batteries, that is also needed to meet demand at peak times. Scarcity in the market has been evident by the number of low residual situations in recent years – that is, the balance of supply versus demand at peak demand times has been low more often in recent years. Peak demand has been increasing by around 0.4% per year since 2014.[8]

The resulting increased spot price volatility increases demand for risk management products

6.4. On the demand side, customers of risk management products are demanding more and different risk management products to insure against increasing incidences of very high spot prices (ie, increasing volatility). Customers of risk management products include non-integrated retailers, gentailers themselves (as they need to firm their own intermittent generation), independent generators (as they need to firm their generation to enable off-take contracts), and large electricity users. The current options being used for risk management are discussed in chapter 4.

A decrease in supply and increase in demand means risk management is becoming more expensive

6.5. A decrease in supply and an increase in demand for electricity means that risk management is becoming more expensive. This is reflected in an increase in the cost of electricity (ie, spot purchases and hedging costs) for all retailers (see Figure 3).

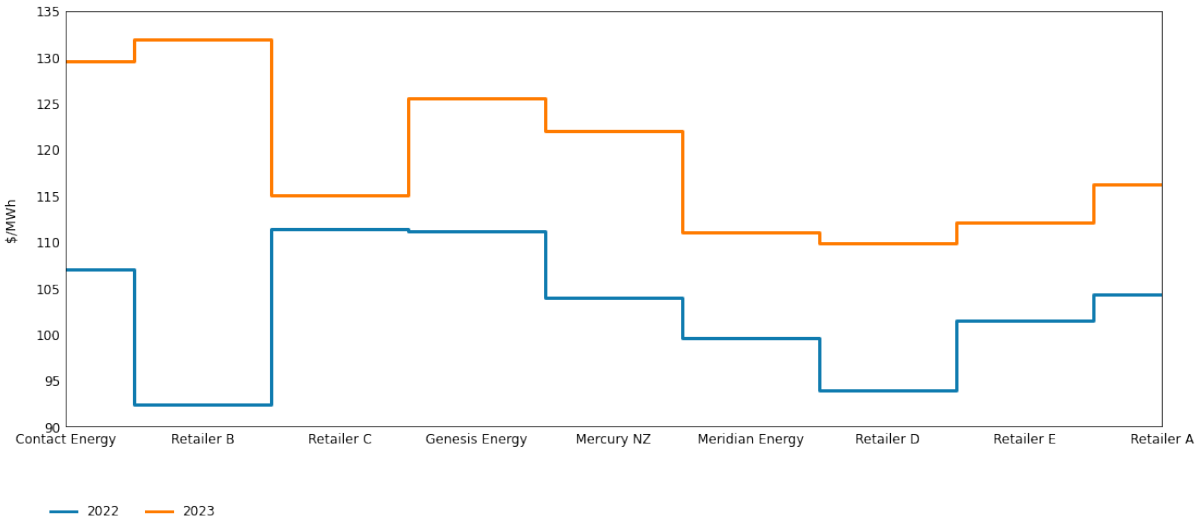
6.6. For all non-integrated retailers, the cost of electricity increased between 2022 and 2023. However, the extent of this increase has varied amongst non-integrated retailers depending on the risk management strategy of each non-integrated retailer.

6.7. Figure 3 shows the cost of electricity by retailer from the Retail Gross Margin (RGM) disclosures. It shows that the cost of electricity increased substantially for Retailer B from 2022 to 2023, whereas Retailer C's total electricity cost only increased slightly

8 https://www.ea.govt.nz/projects/all/impact-of-the-rcpd-charge-removal/

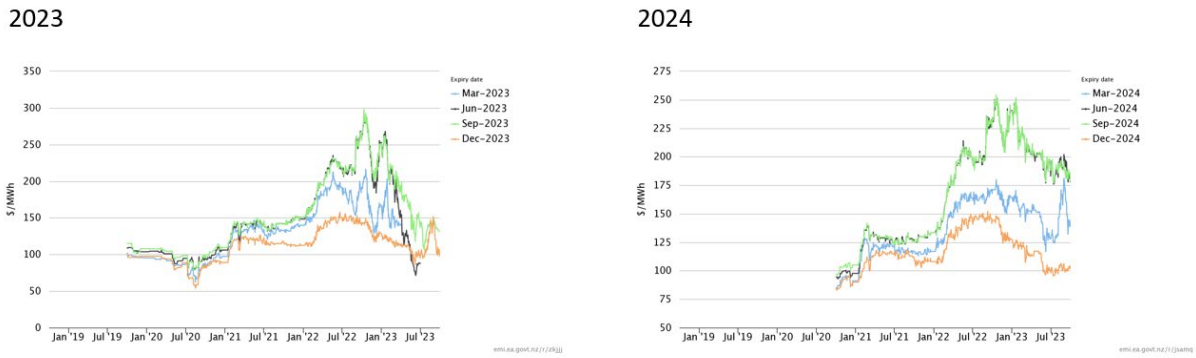
between these years. However, for all non-integrated retailers, the cost of electricity increased between 2022 and 2023.

Figure 3: Cost of electricity by retailer, from RGM data



6.8. Figure 4 also shows that participants had fewer opportunities to buy cover for 2024 at lower prices, compared to the opportunities they had for cover in 2023 (where prices stayed below $150/MWh for a couple of years). That is, while there was a period of time where 2024 contracts were priced lower (up until around January 2022), this period was a lot shorter. For contracts purchased for cover in the March, June, and September quarters of 2023, participants could buy baseload contracts at lower than $150/MWh for two years (2020 and 2021). For contracts purchased for these quarters in 2024, prices below $150/MWh were only available for about one year.

Figure 4: ASX prices for contracts in 2023 and 2024



6.9. As volatility increases, the suppliers of hedges take on increased risk. The spot price distribution over the last five years (see Figure 1) exhibits the characteristics of a "fat tail" distribution.[9] That is, there are more prices occurring further away from

9 While this may not be strictly true in a statistical sense, the tail of the spot price distribution is getting fatter (longer). For our purposes a direct empirical fit to a fat tail distribution is not necessary.

(higher than) the mean. The importance of fat tail distributions for electricity risk management are discussed in Billimoria et al.[10] They state that "Without an appreciation of the importance of extreme events for such distributions, risk can often be underestimated." That is, as the tail gets fatter/longer, loss outcomes at the distribution extremities can become significantly higher (ie, when the spot price ends up being a lot higher than the agreed contract price). This implies that any supplier of risk management products for these extremities will take on higher risk and therefore charge a higher risk premium to do so.

6.10. Billimoria et al go on to discuss how it is important to encourage and incentivise comprehensive tail analysis and risk management by market participants. Any market reform that would dull incentives to manage such risks should be avoided. This does, however, imply that risk management products need to be accessible to manage such risk.

7. Gentailers have an efficient hedge against this volatility, but also need additional sources of insurance

7.1. Gentailers use their own generation to cover their customer load requirements. From a risk management perspective, vertical integration is equivalent to a set of long-term flexible hedge contracts between the firms' generation and retail arms. If the gentailer owns flexible generation, it can change this generation output in line with its expected customer load – ie, it provides the shape a retailer needs to manage its risk.

7.2. Each gentailer's portfolio has historically required some additional cover, for example Meridian has entered into swaptions with thermal generators to provide cover for dry years. However, due to scarcity in the market (including fuel constraints), they are increasingly needing other options to cover their load. Gentailers have recently been turning to demand response options to manage both dry year risk and peak capacity issues. They are also investing in batteries. The current use of these risk management options is discussed more fully in chapter 4. Gentailers also need to insure against expected and unexpected generation and transmission outages. They have traditionally done this through swaptions for planned outages.

Non-integrated retailers may have problems executing a similar strategy

7.3. Non-integrated retailers do not have access to generation in the way that gentailers do. While vertical integration is an option that is available to them for risk management, the current opportunities for vertical or quasi-vertical integration (with non-integrated generators) mainly involve intermittent generation. Intermittent generation does not provide the same profile as their residential load, leaving them

[10] https://www.oxfordenergy.org/wpcms/wp-content/uploads/2024/04/EL-53-Hedging-and-Tail-Risk-in-Electricity-Markets_FNB-RP-002.pdf

exposed to substantial risk. As discussed in chapter 4, we view this as a distant substitute for OTC contracting.

7.4. Another option available to non-integrated retailers is to contract for generation capacity – however, as mentioned already, flexible generation capacity is scarce, and gentailers tend to prioritise their own usage. This leaves non-integrated retailers to contract mainly with intermittent generation, which as mentioned above does not have the same profile as their customer load (although as we discuss in chapter 4, PPAs with wind and geothermal can go a long way towards reducing their risk). Non-integrated retailers argue that the competition consequences of allowing gentailers to prioritise their own usage are too high, hence suggesting interventions directed towards establishing a level playing field.

7.5. Thus, while non-integrated retailers do have options for risk management (as discussed in chapter 4), these options may not provide the same level of risk reduction that vertical integration provides. That is, non-integrated retailers cannot reproduce the risk-reducing benefits of physical hedging by pure contractual portfolios. Many authors have found evidence for this in the past.[11] Availability and pricing issues for contractual portfolios could also occur – this is discussed in chapter 5.

But gentailers benefit from having non-integrated retailers in the market

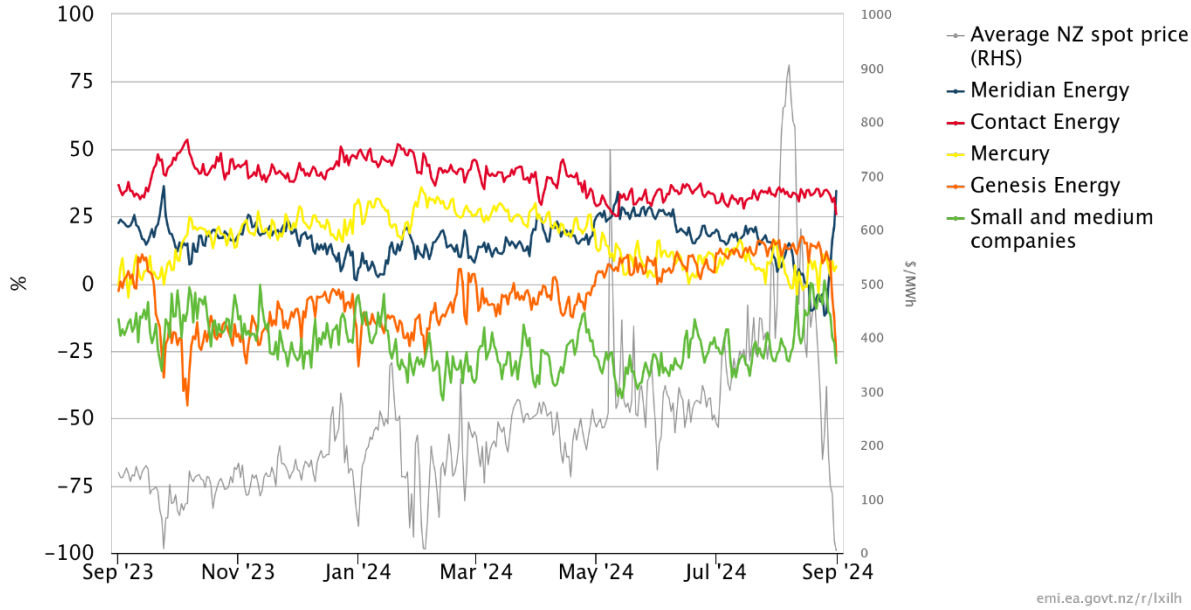
7.6. Gentailers benefit from having different customers in the market for selling risk management products. As mentioned above, a gentailer's generation portfolio will not always (and not usually – see Figure 5) match its customer load profile. This means that at times it can be long on generation (ie, have generation output above its customer load obligations – in Figure 5 this is represented as a positive percentage). This means they may decide to sell hedges when they are long on generation, insuring themselves against low spot prices. At other times they can be short on generation (or forecast to be short on generation – in Figure 5 this is represented as a negative percentage) so they might decide to buy hedges. This is especially true for periods of low hydro storage or constrained gas supply.

7.7. The presence of non-integrated retailers in the market allows gentailers to be long on generation more often, as they have customers to sell hedges to. In turn, this allows gentailers to manage their risk of being short on generation in peak periods more easily.

7.8. The implications of the gentailers' market position (as the owners of most flexible generation and as vertically integrated firms) for competition are discussed in chapter 7.

[11] See literature review in: https://ceem-dauphine.org/wp-content/uploads/2024/09/Hedging-strategies-in-energy-markets-The-case-of-electricity-retailers.pdf,

Figure 5: Gentailer physical wholesale positions (positive = long on generation, negative = short)



Chapter 4: What options can electricity retailers use to manage their risk?

Contents

1. Purpose

1.1. The aim of this chapter is to set out what options electricity retailers can use to manage their price and volume risk – with a focus on risk reduction at peak times. That is, this chapter looks at what substitutable products are available for risk management at peak times. To do this, we apply principles broadly consistent with a market definition exercise.

1.2. While we are not constrained by needing to perfectly define a market, as is required in the Commerce Act, we thought it useful to take such an analogous approach to inform our competition analysis. The more options available to retailers and the more substitutable those options are, the less likely it is that suppliers of each type of risk management product will be able to exercise market power for any product. We are particularly interested in alternatives to hedge contracts for peak time risk reduction.

1.3. The evidence and analysis we use to establish which options are substitutes for hedge contracts for peak time risk reduction are:

(a) Using modelling to show the relative risk reduction of different options under different market states – ie, different realisations of price and volume risk

(b) Evidence of what options non-integrated retailers are currently using

(c) Discussing the advantages and disadvantages of different products.

2. Preliminary findings

2.1. This section sets out our preliminary findings based on our substitutability analysis. It is followed by:

(a) Section 3, which discusses in more detail why we ask if there are substitutes for super-peak contracts

(b) Section 4, which sets out our approach and summarises our analysis

(c) Section 5, which discusses demand-side substitutability in more detail, including:

i. Setting out the available quantitative evidence

ii. Setting out our observations of the portfolios of risk management options that non-integrated retailers actually use

iii. Discussing the pros and cons of each risk management option (which may mean that different options better suit different business models)

(d) Section 6, which discusses supply-side factors that may impact the market (ie, effectively constraints).

2.2. We welcome feedback on our approach and preliminary findings.

Risk management products can be substitutes but also complement one another in a portfolio

2.3. We approach our substitutability analysis by comparing alternatives to a portfolio of baseload and super-peak hedges. This acknowledges that retailers use a portfolio of products to manage spot price risk. As our analysis shows, using super-peak contracts by themselves would result in much higher cost to hedge most of their volume in these periods, and expose the retailer to substantial risk outside of these trading periods. This means that a common contract-focused approach to managing risk is to pair baseload and super-peak contracts.

2.4. Our modelling analysis and other evidence indicates that:

(a) A portfolio of baseload and super-peak hedges has some risk management options that appear to be closer substitutes, including:

i. A portfolio of baseload hedges and peak hedges

ii. A portfolio of baseload hedges and cap hedges

iii. A portfolio of baseload hedges and demand response

iv. A portfolio of baseload hedges and retail tariffs

v. A portfolio of baseload hedges and virtual battery services or investment in batteries

(b) Other risk management options – Power Purchase Agreements (PPAs) with intermittent or baseload generation, investment in intermittent generation, and virtual power plants (VPPs), are likely to currently be more distant substitutes for a portfolio of baseload and super-peak hedges. That is, they do not provide a similar level of risk reduction. However, we note that some of these options – such as VPPs - may become closer substitutes in the future.[1]

(c) Some of these closer substitutes (and even some of the more distant substitutes) perform better under different expected market states – that is, different expectations of price level or volatility and/or load expectations. Given the uncertainty in predicting what market state may eventuate (ie, the uncertainty that risk management option seeks to insure against), customers typically seek to have a portfolio of different risk management products. That is, the various risk management products appear to be demand-side complements to varying degrees, in the sense that one product complements another, especially where there is not enough of one product to meet the total requirement of a non-integrated retailer. They are also substitutable at the margin. These portfolios differ substantially between non-integrated retailers and across different participant types.

2.5. While some products are, currently, most likely more distant substitutes for one another (such as solar PPAs and super-peak hedges), at the margin it is likely that non-integrated retailers can switch some of their purchases from one product to

[1] This is discussed in more detail in chapter 6.

another, even amongst some of the more distant substitutes. However, a key question for our purposes is whether the effectiveness, cost, and availability of alternative portfolio options are sufficiently similar to a combination of baseload and OTC super-peak hedges to be close substitutes. If there are close substitutes for that combination, it is likely that this would reduce the extent of any market power held by the suppliers of OTC super-peak hedges.[2]

Some products may be closer substitutes for the purposes of market definition

2.6. Our modelling, combined with evidence we have received to date, shows that the options listed above in paragraph 2.4 as closer substitutes are widely used for risk management by non-integrated retailers or are being considered for use in the future. This suggests that these alternatives may be close substitutes for a portfolio of baseload hedges and super-peak hedges. This may be the case given we are not aware of any significant limitations with their use, and some provide distinct risk management advantages over super-peak hedges. Advantages include alternative suppliers or alternative types of underlying capacity, and (for the portfolios of demand response or retail tariffs and baseload hedges) benefiting from both products within the portfolio in a way that a portfolio of financial contracts alone does not provide (ie, receiving payouts from the baseload hedge when spot prices are higher than the contract price, while purchasing less volume on the spot market).

2.7. However, some of these products (battery renting, demand response - especially with mass market consumers, and retail tariffs) are currently still in the early stages of being developed in the New Zealand market. It is likely that the substitutability between these products may increase in future.

While others are probably currently relatively distant substitutes

2.8. All of the options listed above as distant substitutes are already used as part of a portfolio of risk management options by non-integrated retailers. However, the evidence currently before us does not suggest that they are sufficiently close substitutes for a portfolio of baseload and super-peak hedges to provide an effective competitive constraint on the pricing of super-peak hedges.

2.9. Our modelling suggests that a PPA with a wind generator (in combination with baseload futures) may be somewhat substitutable for super-peak hedges (as they can provide risk reduction at many super-peak times). However, there may be some super-peak times where the PPA could provide no cover – ie, when the wind is not blowing. For this reason, we have not included portfolios including PPAs as substitutes for a portfolio of super-peak and baseload contracts.

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[2] Here we use a general term of magnitude, rather than a term with specific meaning such as the term “substantial degree of market power” used in the Commerce Act.

But we have not come to a definitive view on market definition

2.10. When considering the degree of substitutability between different risk management products, we must be careful to keep in mind that the relatively close substitutability we currently observe in the market between OTC super-peak hedges and other products could merely be reflective of the exercise of existing market power by the providers of OTC super-peak hedges. If prices for these hedges are currently higher than competitive levels, industry participants may be making substitution decisions that would not be reasonable were prices for these hedges instead at competitive levels (ie, lower). Accordingly, in a workably competitive market for hedges, the substitutability of these alternative options may be lower. Current pricing of super-peak hedges is investigated in chapter 5.

2.11. Furthermore, supply-side considerations may also be relevant to assessing the competitive constraint provided by other electricity risk management products. These products are usually underwritten by physical capacity, and this physical capacity has supply constraints. This impacts the ability of most suppliers in this market to supply risk management products. For example, the supply of OTC super-peak hedges is constrained to some degree by how much the suppliers are already supplying baseload hedges (or firming intermittent generation, or experiencing fuel supply constraints). This needs to be acknowledged when considering any possible interventions in the market. Demand response can also be used for risk management, but this is also constrained by the ability of the demand responders to turn on and off easily, and/or by their willingness and ability to do so.

2.12. For these reasons, we have not come to a definitive view on the precise boundaries of the relevant market/s for the various risk management products. It may be appropriate to define separate relevant markets for each of the separate individual products listed above notwithstanding that we consider these products are likely to be closer substitutes than the other more distant options. Alternatively, it may be that two or more of the risk management products are sufficiently close substitutes such that any attempt to exercise market power by increasing the risk-adjusted price for one of the products would not be profitable because retailers would discipline such a move by switching to another product.

2.13. Similarly, we do not consider that there is a case for further consideration of different degrees of substitutability by geographic, temporal, functional, or customer characteristics (noting again however that we have not sought to be definitive in any market definition). Our preliminary position is that such categorisation would not necessarily provide additional analytical insight relevant to this review.

3. Why are we asking this question?

3.1. This review aims to assess whether one or more suppliers may be exercising market power in the supply of risk management products—in particular OTC super-peak contracts in a manner that is adversely impacting competitive outcomes.

3.2. The exercise of market power may manifest as:

(a) The supply of a product/s at uncompetitive terms and conditions (eg, prices above competitive levels); and/or

(b) The refusal (or constructive refusal) to supply risk management products that would otherwise be supplied in a workably competitive market.

3.3. Any discussion of the potential exercise of market power necessarily entails at least some consideration of the specific market in which the conduct is occurring. This is important because an overly narrow approach to market definition risks overestimating the extent – and potential impact on competition – of any market power. Correspondingly, an overly wide approach to market definition risks underestimating market power and its impacts on competition. Still, we recognise that market definition is just one tool in any analysis of market power and competitive effects and, in that regard, have sought to follow the Commerce Commission's approach of considering products that are substitutable "as a matter of fact and commercial common sense".[3]

3.4. We approach considering the relevant market(s) for this review by starting with a portfolio of shaped contracts (baseload and super-peaks), and then comparing other alternatives for risk management to this portfolio. We also look at super-peak contracts by themselves, but note that such an approach to risk management is not realistic. Retailers would be left with substantial risk if they only purchased super-peak contracts (as shown in the modelling results). The same is true for other options when used by themselves.

3.5. We assess whether suppliers of OTC super-peak contracts could increase the price of such contracts without electricity retailers being able to switch to another substitute/s (portfolio) that would provide similar risk reduction. When making our comparisons, we discuss the limitations and advantages of the alternatives, show evidence of current usage of alternatives, and present our model results of risk reduction estimates. While our modelling does not fully align with an empirical SSNIP test (explained further at paragraph 4.1 below),[4] and is therefore not a completely orthodox 'market definition' exercise, we consider our approach is appropriate for our purposes in the context of considering the degree of substitutability between different risk management products using the empirical evidence we have gathered.

3.6. The alternatives that we consider are:

(a) OTC or ASX peak contracts

(b) OTC or ASX caps (in our modelling we use C300)

(c) OTC or ASX baseload hedges

(d) Wind, solar and geothermal PPAs

(e) Vertical integration (investment in intermittent generation)

(f) Investment in batteries

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[3] Commerce Act, s3(1A). For the avoidance of doubt, while we have used the Commerce Act framework as a reference/starting point, we have not conducted a complete s36 analysis.

[4] Small Significant Non-transitory Increase in Price. See Glossary for a description.

(g) Virtual battery services

(h) Demand response

(i) Retail tariffs

(j) Virtual power plants (VPPs)

(k) Managing risk directly from balance sheet.

4. Defining the relevant market

4.1. One way to test whether products are substitutable as a matter of fact and commercial common sense is to use the hypothetical monopolist test (also known as the SSNIP test). This approach involves starting with a specific focal product (OTC super-peak hedges), and then considering if a hypothetical monopolist supplier of OTCs would be able to profitably raise (quality-adjusted, or in this case risk-adjusted) prices by a small but significant amount (usually 5-10%) above a competitive price level, at least for a non-transitory period (in the order of one or two years).[5]

4.2. If such a price increase would be profitable for the hypothetical monopolist because customers would not switch sufficient purchases away to alternative risk management products/approaches to constrain the actions of the hypothetical monopolist, then super-peak OTCs are likely to constitute their own separate product market.

4.3. However, if sufficient customers would switch to, say, ASX baseload hedges such that a price increase would not be sustainable for the hypothetical monopolist, then both super-peak OTCs and ASX baseload hedges are sufficiently close substitutes as to be in the same product market.

4.4. Similarly, if a price increase would not be profitable because a supplier of other risk management products would readily switch to supplying super-peak OTCs and undercut the monopolist, then the relevant product market should be widened to include not just the current suppliers of OTCs but also these other suppliers that would readily constrain the price of current suppliers if a price increase were imposed.

Our modelling suggests that a price increase for OTC super-peak contracts would result in customers switching to alternatives

4.5. As discussed above, the SSNIP approach tests the ability of a hypothetical monopoly provider to profitably sustain an increase in the quality-adjusted price of a product. Our analysis presented here tests the extent to which price increases in competing risk management products result in shifting demand between these products. While this test is not an exact representation of an empirical SSNIP test

[5] https://comcom.govt.nz/__data/assets/pdf_file/0020/91019/Mergers-and-acquisitions-Guidelines-May-2022.pdf

(which would look at whether a hypothetical monopolist could profitably sustain a price increase), it does however inform the question of substitutability as a matter of fact and common sense.[6]

4.6. Our results suggest that a retailer would switch some spend to alternative products if the price of super-peak contracts increased (when using super-peak contracts in a portfolio with baseload hedges). This is true for peak contracts, cap contracts, and battery investment, although peak and cap hedges appear to be closer substitutes than battery investment.

4.7. To compare the substitutability for each type of contract, Table 1 compares how much we would spend on 'option 1' given its risk neutral price and compare this to the case where we increase this risk neutral price by 5%.[7] If the contract spend drops substantially, then this suggests that 'option 2' is easily substitutable for 'option 1'. In all cases, risk neutrally priced baseload hedges are assumed to be available to complement the other options, as our modelling (and other evidence) has shown that baseload hedges are frequently required as part of an effective risk management portfolio.

4.8. As our focus is on the substitutability of contracts that cover super-peak periods, we assume that both option 2 and baseload contracts are available at the risk-neutral price—thus we are comparing their ability to replace option 1 (in a portfolio with baseload hedges) as a peak hedge.

4.9. In Table 1 we see that:

(a) The peak contract is easily substitutable where even the baseload contract alone completely replaces it after a 5% increase in price.

(b) The 'Baseload & Peak' and 'Baseload & C300' portfolios appear to be good substitutes for a portfolio of baseload & super-peak contracts. After a 5% increase in price, there is a substantial drop in the spend on super-peak contracts with these available as alternatives. The 'Baseload & Battery' portfolio also appears to be a moderately good substitute for a portfolio of baseload and super-peak contracts.

(c) The 'Baseload & Peak' and 'Baseload & Super-Peak' portfolios appear to be good substitutes for a portfolio of 'Baseload & C300' contracts. Again, after a 5% increase in price, there is a substantial drop in the spend on C300 contracts when 'Baseload & Peak' and 'Baseload & Super-Peak' portfolios are available as alternatives. The 'Baseload & Battery' portfolio does not appear

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6 This test is based on our modelling as set out in Appendix B. We recalculate 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. Values on the diagonal of Table 1 and Table 2 (ie. Option 1 = Option 2) are for a baseload hedge and only one other product. We have not included demand response as part of this test as we model demand response as a change to the non-integrated retailer's load profile instead of a financial contract.

7 See Appendix B for a discussion of why we have used risk neutral pricing.

to be a good substitute for the 'Baseload & C300' portfolio as there was a minimal change in spend after the 5% increase in price.

(d) The 'Baseload & Peak' and 'Baseload & C300' portfolios appear to be moderately good substitutes for the 'Baseload & Battery' portfolio. After the 5% increase in price of the battery, the contract spend on the battery drops by about half given each of these alternatives. The 'Baseload & Super-Peak' portfolio appears to easily substitute for the 'Baseload & Battery' portfolio since a price increase in the battery is unnecessary for it to be replaced by this portfolio (ie, spend on a portfolio of 'Baseload & Battery' is zero if super-peak contracts are available).

4.10. Table 2 shows the corresponding increase in spending on the baseload contract and option 2 (only baseload if option 1 = option 2) to confirm that contracts are being substituted (rather than option 1 spend simply decreasing).

Table 1: 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	159	41	73	120
	5%	0	0	0	0
Super-Peak	None	32	43	28	43
	5%	5	36	6	15
Cap (C300)	None	10	6	16	10
	5%	2	1	15	9
Battery	None	4	0	5	11
	5%	2	0	3	10

Table 2: 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	346	311	270

Option 1	Price increase in option 1	Option 2			
	5%	392	387	383	388
Super-Peak	None	355	344	356	344
	5%	384	350	376	373
Cap (C300)	None	374	379	367	374
	5%	386	385	368	376
Battery	None	386	387	379	377
	5%	388	387	381	378

The current use of alternatives also suggests a wider market than OTC super-peak hedges alone

4.11. While the current use of alternatives does not provide a definitive conclusion on substitutability, it nevertheless provides important evidence to suggest that some alternatives are substitutes. It shows – given prevailing market conditions – which products customers regard as substitutes. However, we recognise that current usage of one product could be hindered while usage of another amplified by the current exercise of market power. This means that current usage may not completely answer the question of which products customers would switch to if the quality-adjusted price of one product increased.

4.12. As such, we do not view this evidence in isolation. Our modelling results alongside evidence of current usage and our discussion of the limitations and advantages of different products should all be considered together to provide the full picture for our conclusions as to the substitutability of different options. Access issues and pricing of alternatives are discussed in chapter 5.

4.13. As discussed in more detail in section 5, all options listed as possible substitutes are already being used as part of non-integrated retailers' portfolios for risk management (except for virtual battery services, although an EOI for this service garnered a lot of interest). This provides evidence that these options are to some extent viable substitutes for OTC super-peak hedges, especially if used as part of a portfolio of options.

And some substitutes have distinct advantages over OTC super-peak hedges

4.14. As discussed in more detail in section 5, some of the alternatives have advantages over super-peak hedges. For example, demand response and retail tariffs can add additional benefit if already hedged, including at super-peak times. Cap contracts can allow the benefit of lower spot prices while putting a cap on higher prices at peak times. VPPs can provide the benefits of vertical integration with smaller capital

investment and fewer challenges to set up. This evidence also suggests that other risk management options can be good substitutes for OTC super-peak hedges.

Testing this market definition against other dimensions

4.15. In this section we look at the other dimensions of market definition which are assessed under an orthodox Commerce Commission type approach to defining a market. Our assessment thus far has focused on the product dimension. While we are not constrained by needing to follow this approach exactly (we are trying to draw insights rather than perfectly define a market), we consider it useful to set out our thinking on these dimensions, to provide further insights for this review.

Customer dimension

4.16. Defining different customer markets can be appropriate if a supplier/s of a particular risk management product are able to price discriminate between different customers, or groups of customers.[8] For example, if a supplier knows that a specific customer is not able to use other products, the supplier may charge that customer a higher price than other customers who have more options. For instance, a gentailer may have greater options than non-integrated retailers and/or large electricity users, who might face higher prices as a result. Or large industrial users may face different options than non-integrated retailers leading to different prices.

4.17. In this situation, the different competitive options faced by different customers could justify defining separate customer markets. Gentailers have the natural hedge that their generation provides, and thus only demand other risk management products around their portfolio. Independent generators with intermittent generation may demand different firming options depending on the generation type. Large electricity users may have a baseload profile and thus not require peak hedges (although not all large electricity users have a baseload profile). Large electricity users can also provide benefits to gentailers that non-integrated retailers cannot, making for a different contract proposition. These benefits include:

(a) Demand response opportunities

(b) Long term relationship (ie, future contracting opportunities)

(c) Building brand value

(d) Developing additional value such as process heat conversion.

4.18. However, while different customers may demand more of the risk management options that are catered to their unique characteristics, all customers benefit from a portfolio approach to risk management, (as discussed earlier, different products reduce risk in different ways and can be complementary). This means that different customer types may demand any of the risk management options to a certain degree.

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[8] Defining different customer markets can also be appropriate if arbitrage is difficult (or impossible).

4.19. There are also differences in demand between products within customer types. non-integrated retailers with a flatter load profile (ie, those with more commercial and industrial customers compared to residential customers) do not have as much need for shaped contracts as other non-integrated retailers with only residential customers, so might use a different combination of products within their risk management portfolios.

4.20. The Authority considers that the differences in customer characteristics and the implication for market power analysis can be fully taken into account without the need to specifically consider the customer dimension in our substitutability analysis.

Functional dimension

4.21. The production, distribution and sale of a product typically occurs through a series of functional levels, conventionally arranged vertically in descending order. In assessing the appropriate functional levels, we considered factors such as the observed structures of seller-buyer relationships.

4.22. There is a downstream retail level for electricity and an upstream wholesale level that includes a range of inputs including wholesale electricity (the spot market) and risk management products. These different inputs are necessary for competing in the downstream retail market. Some retailers are vertically integrated across these different functional levels.

4.23. The functional level of relevance is the wholesale level, this being the functional level where generators or gentailers transact with retailers and large electricity users for risk management products (and this also likely includes transactions between large electricity users and retailers in respect of risk management products).

Geographic dimension

4.24. A geographic market is defined as an area of effective competition, or the area within which consumers of a product or service can source an alternative supplier.

4.25. The 2009 Commerce Commission electricity investigation report contains a good discussion of the geography of wholesale electricity.[9] Their conclusion of a national market for the wholesale supply of electricity is applicable also to the supply of risk management products. Underlying spot prices—and therefore financial risk management products based on these spot prices—are spatially correlated (except when transmission constraints arise, which mainly occur during planned transmission outages and peak periods). This means that prices of risk management products at different locations will also be correlated. The FTR market provides the opportunity to hedge any differences in prices that arise between locations at low additional cost—FTR holders must post prudential security similar to the ASX, and can either participate directly or through a broker. Monthly baseload FTRs of 0.1 MW denomination are currently available between eight

9 https://comcom.govt.nz/__data/assets/pdf_file/0025/219094/Electricity-investigation-Investigation-report-21-May-2009.PDF

locations (56 paths) throughout New Zealand. FTRs for each path are progressively released in 12 auctions over a 2-year horizon and can also be sold back into later auctions. Bilateral trading is also possible. Since only baseload FTRs are available, a small amount of residual locational risk may remain (although we do not consider this material to our analysis).

4.26. So, while customers may have different localised risks, they can manage most of this risk through a portfolio of FTRs and a national energy hedge market.[10]

Temporal dimension

4.27. Most markets operate continuously over time. However, where competitive market conditions vary within definable periods (eg, peak and off-peak), it may be appropriate to consider these periods as falling into separate markets. The temporal dimension may be thought of as a further characteristic with which to delineate relevant markets.

4.28. Our current position is that it is not necessary to formally consider separate temporal markets for the purposes of this review. The number of suppliers does not change through the course of a year (although each supplier's ability or willingness given their own risk constraints may change at different times of the year due to underlying conditions). While super-peak OTC contracts only relate to the morning and evening peak demand periods, these time-specific elements are actually covered by the product dimension because they relate to the product being traded, not the time at which it is traded – ie, the limitations and risk reduction of each for use during super-peaks and for overall risk reduction have been discussed in this chapter. Suppliers of these different risk management products can compete against each other during these peak periods. As the Commerce Commission did in its 2009 investigation, we also consider any variations in the extent of competition during peak periods in our market power analysis.[11]

5. Demand-side substitutability

5.1. In this section we discuss demand-side substitutability in more detail, by:

(a) Setting out the available quantitative evidence

(b) Setting out our observations of the portfolios of risk management options that non-integrated retailers actually use

(c) Discussing the pros and cons of each risk management option (which may mean that different options better suit different business models)

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10 Instances of transmission constraints may arise but these are rare. Where planned transmission outages are scheduled this may reduce the geographic market – but again, these transmission outages would affect customers for only a small proportion of time. And there are FTRs available to cover these locational risks.

11 https://comcom.govt.nz/__data/assets/pdf_file/0025/219094/Electricity-investigation-Investigation-report-21-May-2009.PDF

5.2. We have assessed likely demand-side substitutability by customers (here focussing on non-integrated retailers)[12] across different risk management approaches based on quantitative modelling and qualitative evidence.

5.3. In addition to our approach to substitutability set out above, our quantitative modelling also assesses the expected profitability and ability to reduce risk of different risk management alternatives.[13] This provides further insight into how substitutable these alternatives are for non-integrated retailers.

Our modelling suggests some options are currently more distant substitutes and/or complements

5.4. The results from our modelling and other evidence suggest that the following alternatives for risk management are currently not as effective in reducing risk as a portfolio containing baseload and super-peak hedges:

(a) Investing in intermittent generation; and

(b) PPAs.

5.5. Additionally, while not modelled, we also consider VPPs to currently be a more distant substitute, due to its current limitations as discussed in paragraph 5.43.

5.6. The results presented below in Figure 1 show that our risk assessment measure (with 50% weight on expected profit and Conditional Value at Risk, or E-CVaR[14]) from our modelling for batteries (by themselves), demand response (by itself), and cap contracts (by themselves)) are worse than being unhedged.[15]

5.7. That is, these risk management options, when used by themselves, can result in higher losses compared to being unhedged in some of the already high loss market states. The 'High Price and Low Volatility' and 'High Price and High Volatility', which are already high loss scenarios when unhedged, are made worse using the battery and cap contracts alone. This is due prices in these market states being less peaky compared to the high super-peak price market states (where these contracts would have a positive return), leading to returns that are lower than the contract price.

5.8. Similarly, the reduction in retail revenue associated with the demand response is much higher than the cost savings in the 'High Price and Low Volatility' and 'High Price and High Volatility', leading to higher losses in these market states compared with being unhedged.

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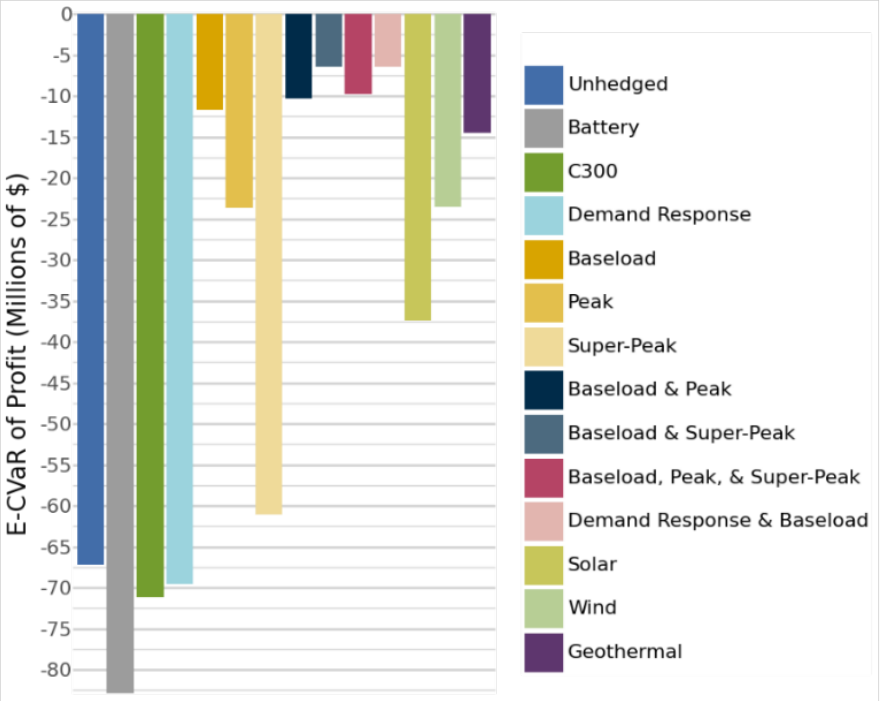
12 While we focus on non-integrated retailers in this chapter, our findings are generally also applicable to large industrial electricity users and can provide insights for non-integrated generators.

13 In this chapter we use the baseline and portfolio optimization scenarios. The assumptions used for the modelling are set out in Appendix B. Both of these scenarios assume risk-neutral pricing – that is, an expected profit across all market states of zero.

14 Conditional Value at Risk quantifies the amount of tail risk. See Appendix B for a description.

15 See Appendix B for a description of the methodology used for the modelling. Here we use the results of our baseline scenario – with risk-neutral prices and volume matching of risk management product volumes to the retail load profile.

Figure 1: Modelling results from baseline scenario



5.9. But investing in a battery, purchasing cap contracts, using demand response (all by themselves), or purchasing super-peak contracts (by themselves), all performed better than being unhedged for the market states with high prices at super-peaks. That is, some risk reduction is possible using these options even outside of portfolios.

5.10. The PPAs (solar, wind and geothermal) all performed slightly better than these other options in terms of E-CVaR, but did not provide risk reduction in line with a portfolio of shaped hedges. They performed well in market states with low average prices, but did not perform well in market states with high prices at super-peak times.

5.11. Baseload hedges by themselves minimise losses in market states with high average prices, but not as well as shaped hedges in market states with high prices at super-peak times.

5.12. Most of these options can reduce risk more when used as part of a portfolio, but not to the same extent as a portfolio which includes super-peak contracts. Our findings may also change in the future with changes in costs of various options.

5.13. All of these alternatives can be considered as complements, where one product complements another in a portfolio. It might well be the scarcity of these products that causes non-integrated retailers to rely on more than one of them. The alternative products are already being used together by retailers in a portfolio for risk management.

While some portfolios are closer substitutes

5.14. The results of our modelling suggest that risk reduction is currently similar to a portfolio of shaped hedges (baseload, peak and super-peak hedges) using the following products:

(a) A portfolio of baseload hedges with peak hedges.

(b) A portfolio of baseload hedges with demand response.

(c) A portfolio of baseload hedges with battery investment.

(d) A portfolio of baseload hedges with C300 cap hedges.

5.15. Additionally, portfolios of virtual battery services with baseload hedges or retail tariffs with baseload hedges (not modelled) appear to be two additional close substitutes that are beginning to appear in the market. These options are however in their infancy in the New Zealand market, and we have not attempted to model them.

5.16. Figure 1 shows that baseload contracts combined with demand response provide slightly better risk reduction than a portfolio of super-peak and baseload contracts. This portfolio minimises losses in the market states with high super-peak prices and capacity shortages. We note however that demand response is modelled as a flat daily demand profile – ie, providing a perfect load profile for baseload hedges.[16] At present in New Zealand, where the flexibility services market is still developing (especially in relation to mass market consumers), accessing this much demand response may not currently be possible for smaller retailers.

5.17. The profit results over different market states are similar for the four portfolios (listed in paragraph 5.12) compared to the portfolio of baseload and super-peak contracts (see Figure 9 and Figure 19 in Appendix B). That is, not only do these options result in overall risk reduction that is similar to baseload and super-peak hedges, but these options also target the same risks – high average prices and high volatility, and higher prices at super-peaks.

5.18. Figure 2 shows the results from our modelling scenario where the volume of each option or portfolio of options is optimised (rather than matched to the retailer's load volume).[17] This modelling scenario allows us to explore more portfolio options. We added a portfolio of baseload hedges with investment in a battery, a portfolio of baseload hedges with wind and solar PPAs, a portfolio of baseload hedges with cap contracts, and a portfolio of shaped contracts (baseload plus peak plus super-peak contracts) combined with a battery and cap contracts.

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16 The retail price is based on the load-weighted average price (LWAP) across all market states. Retail revenue is reduced in this option due to lower consumption in peak and super-peak trading periods where spot prices tend to be much higher.

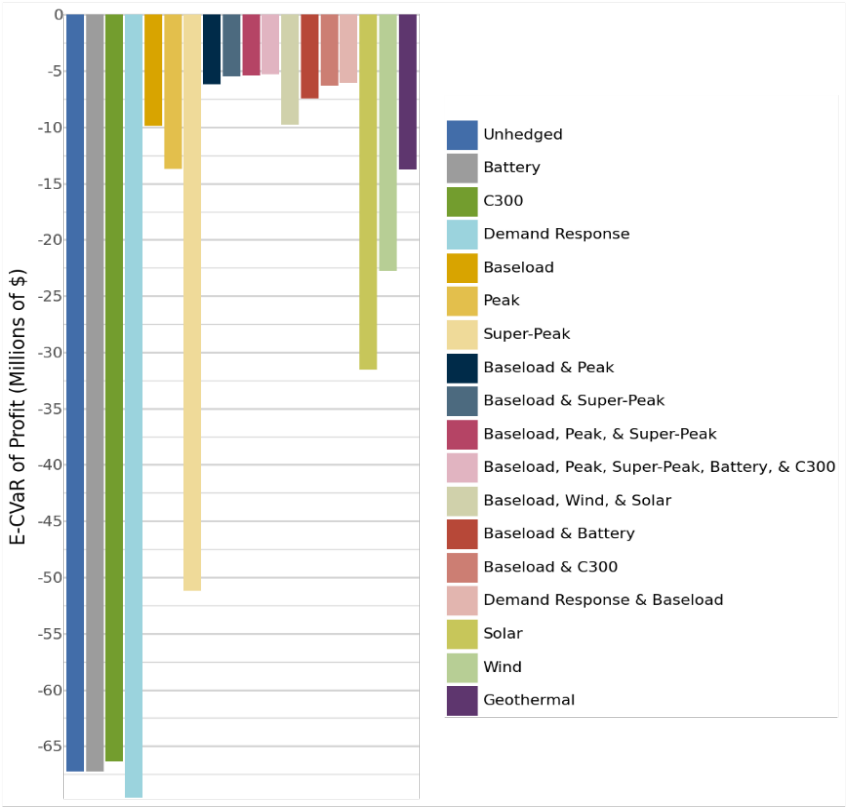
17 This scenario selects the volume of each risk management option which maximises the risk adjusted profit. It allows us to run our modelling with more portfolio options than the simple volume matching exercise.

5.19. The results in Figure 2 show that a portfolio of baseload hedges with investment in a battery, and a portfolio of baseload hedges with caps, provide a level of risk reduction that is similar to the level of risk reduction of the baseload and super-peak portfolio in the baseline scenario (Figure 1).

5.20. When the volume of super-peak contracts is optimised, the risk reduction of any portfolio containing super-peaks improves relative to a simple volume matching exercise (compare Figure 1 to Figure 2).

5.21. Demand response combined with baseload hedges remains a good portfolio for risk reduction (ie, has a similar E-CVaR to the portfolio of baseload and super-peak hedges, where volume of each is optimised), as does baseload hedges combined with peak hedges.

Figure 2: Modelling results from portfolio optimisation scenario



All products are already currently being used as part of risk management portfolios

5.22. All of the above products – both the more distant substitutes and the closer substitutes - are already being used as part of risk management portfolios by non-integrated retailers. No single risk management product is likely to afford a complete solution in respect of all risks. The results from our modelling are consistent with this – most portfolios provide better risk reduction than using one product alone.

5.23. All of the non-integrated retailers that we looked at use a portfolio of products for risk management, and all use a different mix in their portfolios.

5.24. Current usage by non-integrated retailers is outlined below for each product. We also point out where gentailers are using a product, if relevant for showing potential uptake of the product (we do not, however, list all options being used by gentailers). This current usage shows the diversity in risk management strategies amongst non-integrated retailers.

5.25. Demand response:

(a) In May, Octopus launched its Saving Sessions demand response offer. Participating customers are paid to reduce their demand if called on during peak demand periods.[18] There seems to be some demand for such a demand response product, as Octopus received a "strong response" to this offer.[19]

(b) Octopus and Electric Kiwi have trialled hot water cylinder demand response, with Octopus announcing in May that it was opening this up to all customers with eligible meters.[20]

(c) Gentailers are also investing in hot water management, with Contact announcing at its recent investor day that it aims to have 20,000 customers on its "Hot Water Sorter" plan by the middle of next year. As at August 2024, it had around 6,200 hot water plan customers,[21] although previously had been aiming for 10,000 customers to be on this plan by mid-2024.[22]

5.26. Retail tariffs:

(a) Flick has a spot price plan but has stopped offering this to new customers. It also has an off-peak plan with cheaper prices during off-peak times.

(b) Pulse has a spot product for some customers and has trialled a fixed price TOU product with staff, which it said it will offer to its customers soon.

(c) Electric Kiwi has launched a TOU plan called "Movemaster", that offers half-price power overnight.

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18 Participating customers are paid $2/kWh (from Octopus, plus an additional $1/kWh from the distributor). Octopus will announce a "Saving Session event" when "extra high demand" is forecast. For more information see: https://octopusenergy.nz/saving-sessions

19 https://www.energynews.co.nz/news/demand-response/160383/strong-demand-octopus-2kwh-response-offer?utm_source=newsletter&utm_medium=email&utm_campaign=energy-news-newsletter

20 https://www.energynews.co.nz/news/demand-management/157663/strong-frameworks-needed-controlled-hot-water-octopus?utm_source=newsletter&utm_medium=email&utm_campaign=energy-news-newsletter

21 https://contact.co.nz/-/media/contact/mediacentre/annual-and-half-year-reports/2024-integrated-report.ashx?la=en

22 https://www.energynews.co.nz/news/demand-response/165593/contact-says-kiwis-are-flocking-tou-plans, https://www.energynews.co.nz/news/electricity/166542/genesis-trials-hot-water-control-new-flex-service?utm_source=newsletter&utm_medium=email&utm_campaign=energy-news-newsletter

(d) Contact (a gentailer) has stated that almost 100,000 New Zealand households have opted for one of its TOU plans.[23]

(e) Octopus has a TOU plan (called OctopusFlexi) that has different rates for peak, off-peak daytime, and nighttime trading periods.

(f) Electric Kiwi, Octopus and Flick also all have TOU EV plans, with low prices over-night to charge EVs (although the lower prices apply to all usage, not just EV charging).

5.27. Cap contracts:

(a) Only a very small proportion of RFPs sent out during the time period we have information for were for cap products.

5.28. Virtual battery services:

(a) The response to Contact's Expression of Interest (EOI) for battery risk management products has included interest from non-integrated retailers, for both virtual battery services and for super-peak caps.[24]

5.29. Vertical integration:

(a) There is an increasing proportion of investment in generation by independent developers – in the 2022 investment survey, only 1.6% of the volume of committed projects was being developed by New Zealand independent investors, but this increased to 28% in the 2023 survey. This increase indicates the profitability of such a decision, and suggests that the difficulties associated with such investment by smaller entities may not always be insurmountable. Other examples of different businesses investing in generation to manage risk include Fonterra and NZ Steel.

(b) Lodestone told us that becoming a gentailer is the most viable way to build a large quantity of solar generation (and battery storage) in a reasonable period of time. It is planning to complete a new solar farm approximately every 3 to 6 months, and said this pace would not likely be achievable if it were not selling directly to customers. Its business model is to focus on large commercial customers, and in time, it said it is likely to create energy plans for mass market customers in order to accelerate the solar and battery storage build out. This suggests that vertical integration may be a viable business model for new entrants.

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23 Contact launched its first TOU plan in 2021. It has a "good nights" plan (with three hours of free power between 9pm to midnight every night) and a "good weekend" plan (with free power between 9am and 5pm on weekend days). Contact report that some "good nights" customers have moved more than a third of their daily energy usage to the free period. https://contact.co.nz/aboutus/media-centre/2024/04/10/contact-empowers-kiwis

24 https://contact.co.nz/aboutus/media-centre/2024/08/07/contact-seeks-feedback-on-concept-to-support-energy-supply

(c) Pulse has recently become a vertically integrated business (previously it was part-owned by a generator).[25] The firm "expects it will create more generation offtake opportunities as well as further retail growth potential". This suggests that vertical integration may allow smaller retailers to grow their businesses, including by providing a risk management opportunity.

(d) Octopus invests in renewable generation projects internationally.[26] However, it has stated (since it began considering entering the New Zealand market) that problems with the New Zealand market (concerns about competition and a lack of mature trading mechanisms) are inhibiting its investment in generation here.[27] However, it also said these same concerns are inhibiting its investment in retail, but since entering in mid-2021 Octopus has acquired around 7,000 ICPs (0.3% of the market). Its growth in the retail market has however plateaued.

5.30. Investing in VPPs:

(a) Rural Energy entered the market in late 2023, providing solar as a service. It is looking to add batteries to its offer longer term.[28]

(b) Pulse, Electric Kiwi and Octopus all have customers with both solar and solar and battery installations, with solar installations in particular growing over the last year or so (see Figure 3). In May, Octopus launched its "OctopusPeaker Plan". This plan rewards customers who own batteries by paying them $200/MWh (20 cents per KWh) for exporting electricity at peak times. In late May, it increased the amount it pays during winter peak demand – from 20 cents to 40 cents. At this time, it reported 30 customers participating in this plan.[29]

(c) Meridian (a gentailer) has customers participating in a VPP. It is intending to build a new digital platform that will enable an at-home charger installation proposition to grow the scale of flexibility.

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25 https://www.energynews.co.nz/news/electricity-generation/161988/pioneer-brings-pulse-generation-together

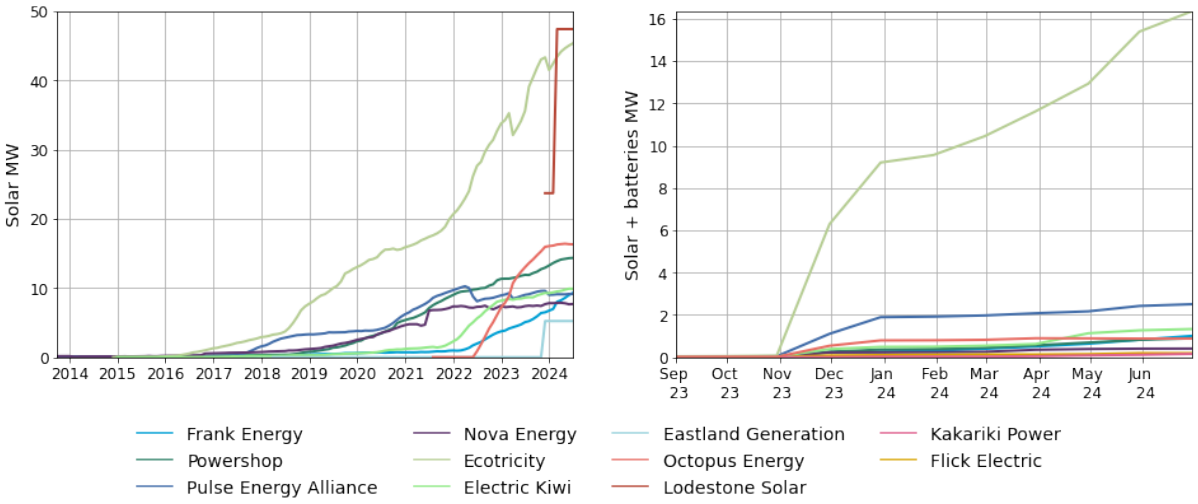
26 Spanning 15 countries in Europe, Asia and Australia, see: https://octopus.energy/press/COP28-Octopus-Sherbro-Sierra-Leone-Partnership/

27 See, for example: https://www.energynews.co.nz/news/margins/161203/retailers-absorbed-some-cost-increases-2023-ea

28 As both a solar installer and energy retailer, it offers a "one stop shop solution." It provides both solar generation and grid generation to its customers – ie, it "firms" the solar generation for the farmers. It enters PPAs with dairy farms, so the farmers have no upfront cash commitment. It maintains ownership of the hardware and sells the energy generated by the solar panels back to the farmers. So Rural Energy is both a generator (from small-scale solar installations) and a retailer. https://www.ruralenergy.nz/

29 https://www.energynews.co.nz/news/control-peak-demand/159366/households-offered-twice-much-during-peaks?utm_source=newsletter&utm_medium=email&utm_campaign=energy-news-newsletter

Figure 3: Rooftop solar installations, and rooftop solar installations with batteries[30]



5.31. PPAs:

(a) One non-integrated retailer told us it is considering PPAs as an alternative risk management avenue, and another three already have PPAs.

(b) Prime entered a PPA with Lightyears Solar last year. Prime does however specialise in retailing to businesses, so has a load profile that is more suited to solar generation (ie, a load profile that is highest during the day). Since signing the PPA, Prime has now taken a 10% stake in Lightyears Solar; potentially a first step towards vertical integration. Prime also mentioned in its response to us that it has considered wind PPAs as another avenue for risk management. However, (as at mid-June 2024) it has been unsuccessful in seeking a wind PPA.

(c) Pulse told us they are "constantly looking into PPAs" and already have PPAs with run-of-river hydro, wind, and solar (see Table 3). None of these PPAs are with Pioneer, who Pulse have now vertically integrated with.

Table 3: PPAs signed during 2023 and 2024 (to June)

Date	Buyer	Seller	Technology	Term	Volume (approx.)
Oct-2022	Pulse (retailer)	Omanawa Falls Hydro Ltd	Run-of-river hydro	2 years	0.2MW
Jan-2024	Pulse (retailer)	Xtream Energy Piopio	Run-of-river hydro	2 years	0.1MW
Jan-2024	Pulse (retailer)	Xtream Energy Marokopa	Run-of-river hydro	2 years	<0.1MW

30 Note that until 2022, solar with batteries were often classified as "other". We have not included the "other" category in this chart as it may include DG other than solar with batteries.

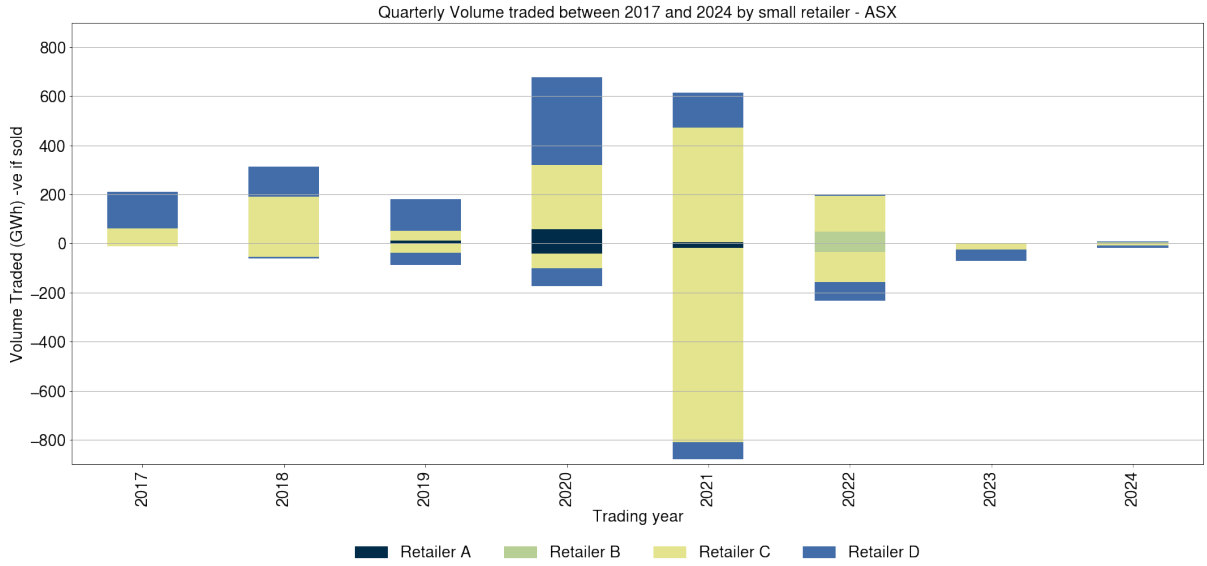
Date	Buyer	Seller	Technology	Term	Volume (approx.)
Jan-2024	Pulse (retailer)	Inchbonnie Hydro Ltd	Run-of-river hydro	1 year	1MW
Aug-2023	Pulse (retailer)	Energy 3	Wind	5 years	0.4MW
Oct-2022	Pulse (retailer)	Lodestone Energy	Solar	5 years	19MW
Sept-2022	Prime Energy (retailer)	Lodestone Energy	Solar	7 years	25% of expected output
Sep-2023	Prime Energy (retailer)	Lightyears solar	Solar	7 years	2.4MW
May-2024	Spark (large user)	Genesis	Solar	10 years	63MW
Sep-2023	Warehouse Group (large user)	Lodestone Energy	Solar	20 years	Undisclosed
May-2023	NZ Steel (large user)	Contact	Undisclosed	10 years	30MW
Apr-2023	Amazon (large user)	Mercury	Wind	15 years	51.5MW
Mar-2023	Ryman Healthcare (large user)	Mercury/Energy Bay	Solar	10 years	20MW
Jun-2024	Meridian	NZ Windfarms	Wind	1-2 years	46MW

5.32. Baseload hedges:

(a) All non-integrated retailers we collected data from (ie, those with ICP numbers above 1,000 as at 30 October 2023) already use baseload contracts for risk management, obtained through both the ASX and/or OTC markets. Figure 4 shows purchases by non-integrated retailers on the ASX since 2017. Due to the ASX access issues last year, non-integrated retailers used the OTC market to a greater extent to obtain baseload hedges for a period of time, and

some have more recently been using brokers for trading on the ASX.[31] Some of these non-integrated retailers requested only baseload hedges via the OTC market (using written RFPs) for the time period we have information for. These were complemented by a mix of PPAs, ESAs (including some shape), retail tariffs, and demand response options. Others requested a mixture of (mainly) baseload, peak, and super-peak contracts on the OTC market.

Figure 4: Non-integrated retailers ASX trades



5.33. OTC peak hedges:

(a) Since the start of our data series, peak contracts have been the second most requested contract type behind super-peak hedges, although only some non-integrated retailers requested peak contracts over the time period we have information for (via written RFPs).[32]

Different customers may have very different portfolios

5.34. Not only do non-integrated retailers have different portfolios amongst themselves, but different customer types (eg, gentailers, large load users, generators) may also have very different portfolios for risk management.

5.35. Gentailers have the natural hedge that their generation provides. But they also need to firm their own intermittent generation, and may have a generation portfolio lacking in flexibility, especially when fuel availability is low. As such they may also buy super-

31 One of the prerequisites for trading on the ASX is to be registered as a Clearing Participant. Specialist Clearing Participants (known as third party clearers), provide clearing services to trading-only participants. In October 2022, one of these Clearing Participants (Bell Potter) exited the market. Jarden (as the Trading Participant) used this Clearing Participant to access the ASX. Since Jarden was undertaking trade for non-integrated retailers, this placed restrictions on these retailers being able to access the ASX market. If retailers use a broker for trading on the ASX, we cannot see this in the data as it shows as a trade from the broker.

32 We collected data from all retailers with total ICPs above 1k as at 30 October 2023.

peak hedges themselves. They are also investing in batteries to complement their existing portfolios, and demand response options – both from industrial and mass market consumers. They also enter into swaptions to insure against times when their own generation is fuel constrained, such as low hydro storage or gas supply constraints. Planned and unplanned generation outages also impact on what other risk management options they may buy.

5.36. Some large electricity users have a baseload demand profile and as such do not need super-peak OTC hedges, while others may consume more at peaks similar to a non-integrated retailers load profile. Many look to enter FPVV contracts to avoid paying high prices at times for electricity, rather than paying the volatile spot price. They may also look to shift their demand to low spot price periods if possible (this is equivalent to gentailers using their own generation as a natural hedge), or enter into demand response agreements.

All products have advantages and limitations

5.37. This section discusses the advantages and limitations of the different products.

5.38. Demand response:

(a) Even if a retailer is hedged for a certain (higher) volume during the time it enacts demand response, it still benefits from that demand response (ie, it gets paid out for the contract at the amount its hedged for, but does not need to purchase as much on the spot market).

(b) Demand response still exposes the retailer to additional risk at peak times – the risk that they pay a higher price for peak electricity under their hedging contracts than the spot price that is realised due to lower demand.

(c) For non-integrated retailers, demand response may only be available for shorter time periods (eg, peaks) and not longer time periods, as they have a smaller proportion of industrial load (that can be turned off for longer time periods). Gentailers may be in a better position to hedge for dry years using demand response due to their existing contracts with large industrial customers.

(d) Octopus has said that while some networks have been receptive to retailers using hot water control alongside their traditional ripple controls to manage network loads, others have had differing views. Octopus said using demand response “requires being clear about the hierarchy of control, because the last thing we want to do is compromise security”. Clause 5 of the current Distributor Default Agreement (DDA) sets out the default arrangements for load management. The Authority recently consulted on a minor amendment to the DDA to clarify that the DDA permits the incumbent and the entrant to both have control over the same load. The Authority considers the process for establishing a load management protocol (between a distributor and retailer) is clearly set out in the DDA.

(e) The Authority has on its work programme to investigate enhancements to dispatchable demand (DD), to better reflect operational constraints of industrial users. This would make it easier for more demand to participate in

DD, with a view to incentivising more demand response to be bid into the market.

(f) In the future, demand response capacity growth may be partially reliant on conversion of industrial process heat from coal or gas to electricity, and the ability of new load connections to provide demand response. Converting coal or gas process heat to electricity will depend on the carbon price. Meridian recently reported a reduction in its expected additional process heat demand, one reason being lower carbon prices recently.[33] One of the taskforce packages (2D) is investigating whether potential industrial demand response is being offered enough (efficient) incentives.

5.39. Retail tariffs:

(a) As with demand response, if a retailer is hedged for a higher volume during the time that demand is curtailed due to the retail tariff structure, the retailer benefits from the retail tariff as it does not need to purchase as much volume on the spot market.

(b) The viability of risk management through tariffs depends on customer willingness to take on some or all of the spot price risk – either through riding through the volatility or altering their behaviour.

(c) Tariffs which pass through some or all of the spot price risk may become less attractive to consumers as spot price volatility increases, or only suitable for larger industrial customers who have large balance sheets, although may mean TOU plans designed to flatten a customer's profile become more attractive.

(d) It is becoming easier for consumers to change their behaviour with new technology – customers can choose a "set and forget" mode for some appliances. This is suggested by the uptake of customers on Contact's TOU plans.

5.40. Cap contracts:

(a) Allow non-integrated retailers to put a ceiling on what they pay for their customer load, while still allowing them to enjoy the benefits of lower spot prices.

(b) Apply to all trading periods, so could become more attractive in future with more intermittent generation in the market (this is explored in chapter 6).

(c) But non-integrated retailers still face volatility (price and volume) at prices lower than the cap price.

(d) Can be traded both on the ASX and OTC, although cap contracts are not a market-made product on the ASX so have much lower liquidity. That is, this

[33] EVA_renewables_market_report_Q1_2024. Other reasons include the discontinuation of the previous government's GIDI policy, and general business downturn.

product depends on having suppliers willing to supply. These suppliers are usually gentailers.

5.41. Vertical integration:

(a) Provides a natural hedge.

(b) Can reduce the transaction costs that would otherwise be required to procure energy from other sources.

(c) However, the capital requirements are substantial, and the cheapest investment opportunities currently are for wind or solar generation. These intermittent generation sources do not match the demand profile faced by non-integrated retailers, so non-integrated retailers would still face substantial risk.

(d) There are other challenges to becoming vertically integrated including resource consenting, connection requirements etc.

(e) Requires knowledge of both the retail business and operating generation assets.

(f) Capital requirements may reduce in future as technological changes in renewable generation and battery storage reduce the scale at which the unit cost of production is minimised.[34]

(g) Investment is inherently long-term, so a retailer making such an investment would need to be committed to ongoing operations in New Zealand (or willing to find a purchaser to exit).

(h) Investment in generation adds other types of risks that the retailer would then face (for example, operational risk of the generation asset).

5.42. Investing in batteries:

(a) There were record high lithium costs in 2022, which led to some battery projects being delayed or shelved. However, falling lithium costs in 2023 (down ~60% on 2022 costs) "may rekindle interest".[35]

(b) Batteries can be smaller and provide more flexibility than current generation investment opportunities.

(c) However, they are not suitable for running for longer time periods (to firm solar or wind generation).

(d) Batteries incur costs to charge them (spot price purchases in off-peak times) and there are limitations on running to minimise battery degradation.

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34 https://www.accc.gov.au/system/files/appendix-d-future-financial-risk-management-nem-frontier-economics-inquiry-national-electricity-market-december-2023-report.pdf

35 https://www.ea.govt.nz/documents/4414/Generation_Investment_Survey_-_2023_update.pdf

(e) Batteries have finite storage capacity over their lifetime. Current warranty conditions restrict the number of cycles the battery can run in total, meaning that every time the battery is run, it limits its future optionality.

(f) The decision on whether to invest in batteries is more complicated than for generation, as it requires predicting the tails of the spot price distribution (to calculate revenue). Predicting the tails of a distribution is notoriously difficult. That is, the potential investor needs to look not only at the levelized cost of electricity (LCOE) but also at price differentials. This increases the risk involved in such an investment. More visibility on future peak prices (eg, through a market-made peak product) would help with the investment decision.

(g) Market systems may also currently impose limitations on the use of batteries for risk management. The Authority intends to investigate the introduction of bidirectional offers for batteries. Currently, tool and market limitations require battery operators to bid and offer their charge and discharge states separately. These states are modelled as separate assets in the market systems and this can lead to contradictory dispatch instructions e.g. to provide reserves in the discharge state and in the charge state at the same time.

(h) Further, participation in the frequency keeping ancillary services market requires a complementary energy offer for the asset providing the service. This currently excludes batteries from offering their flexibility while charging for this service, limiting potential revenue opportunities. The Authority intends to review the purpose and operation of the current multiple frequency keeper (MFK) tool used to dispatch generators for the frequency keeping ancillary service market. Our *Potential solutions for peak electricity capacity issues* decision paper identified that the MFK tool, as it currently operates, does not provide the normal frequency regulation service that it is specified for.[36] In reality, it provides a 5-minute regulation service that corrects for movements in demand and generation between dispatch instructions. In technical terms, it operates almost identically to the Australian National Electricity Market's 5-minute FCAS service. If we were to respecify the MFK service to one that manages demand and generation variability risk, the system operator would be able to increase the dispatched control band at times of high risk – such as winter peak demand periods. This would provide increased security and increase the market size for flexible resources such as battery energy storage systems. Current battery operators have noted that the existing MFK market size, 30MW across both islands, is too small to participate in as it's dominated by incumbent generation suppliers.

5.43. Virtual battery services:

(a) While such a product is still in its infancy in New Zealand, Contact received a strong response to its EOI (including from non-integrated retailers) – so much

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36 https://www.ea.govt.nz/projects/all/managing-peak-electricity-demand/consultation/potential-solutions-for-peak-electricity-capacity-issues/

so that it is considering investing in a larger battery. The product as outlined in Contact's EOI would be able to provide more flexibility than a super-peak hedge because it gives the purchaser the ability to specify a day ahead which trading periods they would like the battery to discharge for.

5.44. Investing in VPPs:

(a) May enable access to the benefits of vertical integration with smaller capital investments, and less challenges to set up (such as resource consenting). They can also be done incrementally.

(b) The marginal cost of running a VPP is low – it just requires data and software, which is infinitely scalable.

(c) VPPs do, however, still have relatively high set-up costs (equipment and installation), although at a much lower scale than generation investment.

(d) May require a more personalised, hands-on approach to customer relations by retailers than is currently being offered.[37]

(e) May be a more viable economic option for larger retailers.[38] With customers spread over the country, a larger retailer may have better visibility of the load it has to cover and may therefore be able to extract more value out of a VPP.

(f) The Authority has recently implemented dispatch notification generation (DNG) that should make this a more viable option.

(g) Currently, VPPs cannot respond to pricing signals at a lower level (ie, in distribution networks). Pricing at this lower level may be needed to better realise the benefits of VPPs.

(h) Controlling thousands of distributed battery systems across the country requires significant effort. The System Operator also discovered after a recent trial that its dispatch tools would need to be changed in order to manage potentially hundreds of additional dispatch participants.

5.45. Managing risk through the strength of the retailer's balance sheet:

(a) With enough capital in reserve a retailer could remain viable through periods of higher prices while enjoying increased profitability in periods of lower prices. Over the long run, average contract prices are similar to average spot prices, but a risk premium is likely to be added for buying contracts for times of higher demand for such contracts (see Appendix A for a discussion on this). However, a retailer can avoid any risk premiums on contract options if it manages the risk itself through its balance sheet. Whether this option is more efficient than other risk management options will depend on a firm's risk

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37 https://www.utilitydive.com/news/residential-ders-could-compensate-for-rise-in-peak-energy-demand-by-2035-d/718677/

38 https://www.accc.gov.au/system/files/appendix-d-future-financial-risk-management-nem-frontier-economics-inquiry-national-electricity-market-december-2023-report.pdf

appetite, the cost of capital reserves, and shareholder expectations regarding stability of returns.

5.46. Baseload hedges:

(a) Provide cover for all trading periods, including some cover at peaks – but require over-hedging in off-peak periods to meet a retailer's full demand profile at peaks (for retailers with residential customers), unless the retailer wishes to remain exposed to the spot market during these times.

(b) If purchased on the ASX, an advantage is that the ASX has higher liquidity than the OTC market.[39] There are various indicators of liquidity including trading volume, open interest, and bid-ask spreads.[40] We looked at trading volume and open interest for the ASX and found that both measures have been increasing over time, suggesting improving liquidity. Figure 7 shows open interest since 2019. It shows a drop in open interest when the ASX access issues occurred, but has since been increasing.

(c) The ASX also has better price discovery as all contract prices are publicly available up to three years in advance and are based on the same product. The current Hedge Disclosure Obligations do not provide for good price discovery of the OTC market, as not much information is provided about the contract. The Authority has decided to improve the Hedge Disclosure Obligations for contracts signed on OTC (which will be implemented from 30 October 2024), which will improve price discovery of the OTC market by broadening the scope of the information collected and published.

(d) The limitations of purchasing on the ASX include:

i. The minimum contract size is set to 0.1MW. If participants want a smaller volume they need to turn to the OTC market.[41]

ii. A participant needs to be registered as or use a clearing participant to trade on the ASX.

iii. Hedges are restricted to two nodes only (Otahuhu and Benmore).

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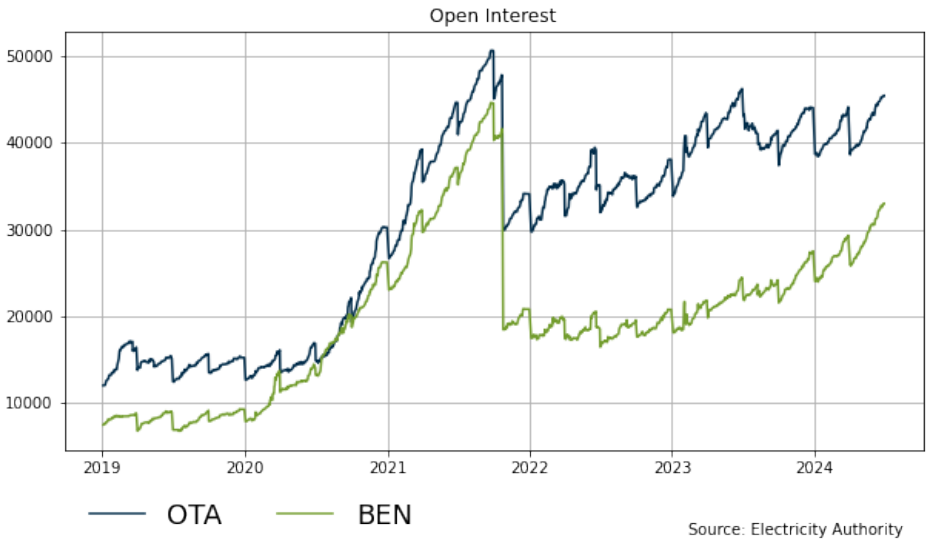
39 Liquidity refers to a situation where traders can enter a market at any time to make a transaction – so they can easily trade in or out of a position they currently hold.

40 Open interest is the number of contracts in existence at any given time, usually at the end of a trading day. The level to which participants are exposed to transaction costs will be reflected by the degree of tightness in the market, and bid-ask spreads can be considered as one of these costs.

41 Using the current hedge disclosure data (which provides only an approximate estimate of any contract in MW, due to the restrictions in reporting), in some years the proportion of contracts purchased by non-integrated retailers in the OTC market that were less than 0.1MW has been quite high – up to 67% in 2019.

(e) Credit is handled by the ASX through the posting of initial margins and variation margins, and this initial margin has been increasing.[42] However, this is due to spot prices being higher and more volatile (due to the way margins are calculated – ie, ASX prices reflect spot prices), which will increase the cost of all risk management options. It does mean however that more working capital is tied up in posting this initial margin.[43]

Figure 5: ASX open interest



5.47. Baseload hedges combined with demand response:

(a) Provides increased cover for peak demand times without the need to over-hedge in off-peak times (if demand response can be targeted to these peak times).

5.48. PPAs:

(a) Are generation following (pay-as-produced, where the buyer purchases the volume produced in each half hour period). However, with most new development being intermittent renewable generation this means that the buyer cannot guarantee enough generation to cover their load or customer's demands. This can be attractive for buyers with either dispatchable demand or flexible generation, however for a small retailer this still leaves them at significant risk of high energy prices at times when production is low. Therefore, a retailer buying a pay-as-produced PPA would still need to purchase additional risk management products.

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42 Margins are calculated by taking into account recent ASX price volatility, which has been increasing. For more information refer to: https://www.asxenergy.com.au/clearing/margins. Credit for OTC trades is handled through credit ratings or other requirements – see chapter 5 for a discussion on credit requirements.

43 MDAG had a discussion on this issue in its recent work, see section 6.1.3 in https://www.ea.govt.nz/documents/1096/04-Risk-Management-Trends-and-Prospects-for-a-High-Renewables-Future.pdf

(b) Since the contracts are with intermittent generation, they are a cheaper alternative than contracting with flexible generation (which has a higher LCOE).

(c) In the 2023 investment survey, many independent developers said they were open to working with retailers, especially when the size of their project was a good match for a small retailer. However, many developers required a PPA with a counterparty with high credit quality in order to obtain finance. This meant that developers often focussed on arranging PPAs with industrial or commercial customers, or with gentailers, rather than with smaller parties such as non-integrated retailers.

5.49. Peak hedges:

(a) Provide cover from around 7am to 10pm (depending on what trading periods are requested if trading the contract OTC). As with baseload hedges however, they do not provide the exact shape of a retailer's load, so they could still be faced with some risk at super-peak times (unless they over-hedged with peak contracts during the other trading periods outside of the super-peak times during the day, ie, additional cover would come at a cost).

(b) Can be traded both on the ASX and OTC, although are not a market-made product on the ASX so have much lower liquidity. That is, this product depends on having suppliers willing to supply. These suppliers are usually gentailers.

6. Supply-side factors that impact the ability to exercise market power

6.1. When defining a market, as well as evaluating demand-side factors, it is also necessary to consider potential supply-side factors. Accordingly, even though our analysis is mainly directed at demand-side substitutability, we consider it helpful to also consider supply-side factors.

6.2. For example, a supplier currently supplying Product B may be able to quickly, easily, and profitably switch to supplying Product A if the price of Product A increases. This would indicate that the supplier of Product B should also be included as a supplier in the market for Product A. Such supply-side substitutability may apply to electricity risk management, whereby suppliers of different risk management products (eg, distributed resource aggregators, large load users who can provide demand response, battery owners, flexible generation owners, baseload generation owners, intermittent generation developers) are nevertheless in the same market.

Supply of risk management products has capacity constraints and these are getting tighter

6.3. However, capacity constraints may affect the ability of suppliers of one type of risk management product, for example ASX hedges, to also supply another risk management product, for example OTCs.

6.4. While many risk management products are financial, they are usually under-written by physical capacity.[44] That is, while financial contracts do not have to be linked to any physical capacity, selling financial contracts usually only happens (taking into account risk constraints) from most suppliers in the New Zealand electricity market (ie, generators or large electricity users) if the supplier has the underlying physical capacity that they can call on during those times.[45] The physical capacity to under-write financial contracts for risk management can come from:

(a) Flexible generation – especially useful for providing capacity to under-write peak or super-peak contracts (or other shaped contracts), but can also be used to under-write baseload contracts

(b) Baseload generation – this generation must run consistently all the time, such as geothermal generation. This means it is only suited to under-writing baseload contracts

(c) Intermittent generation – usually used to under-write financial PPAs, where the PPAs follow the load of the intermittent generation

(d) Batteries – can be used to under-write super-peak or other short time period contracts, but are less useful for under-writing times when intermittent generation is not generating eg for a cloudy day or one or more days of low wind

(e) Demand response – whether this can be used to underwrite financial contracts depends on where the demand response is coming from. For example, some large load users may be able to provide the physical capacity to under-write baseload contracts, if they can turn off some or all of their production for longer periods. Others, such as mass market consumers, may be better suited to providing capacity at peak times.

(f) VPPs – ie, the aggregation of rooftop solar and distributed batteries (or other types of distributed generation when they become available in the future). As for batteries, these cannot be used for under-writing contracts that span many trading periods.

6.5. This means that the overall supply of risk management products is limited - currently and for the foreseeable future- until significant amounts of demand response capacity can be activated. Each of these physical capacity types have different constraints on being able to supply or under-write financial risk management products:

(a) Flexible generation:

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44 This physical capacity can come from generation, batteries, or demand response.

45 Unless there is a willingness to be a speculator and put significant capital at risk through contract markets. Gentailers also sometimes sell OTC contracts and under-write these by buying on the ASX, but charge a premium to do so as this is higher risk for them.

i. Supply can be constrained by maintenance outages, unexpected generation or transmission outages, or fuel availability (eg, hydro storage, gas supply).

ii. Supply to non-integrated retailers can also be constrained by competing demands for this physical capacity, for example gentailers' own retail demand for risk management (that is, having enough generation to cover their own load, ie, the natural hedge quality of being vertically integrated), demand from owners of intermittent generation for firming, and demand from large electricity users for risk management (both baseload and shaped).

(b) Baseload generation:

i. Demand is again multifaceted. Gentailers use their own baseload generation to cover some of their load, but generation capacity is also demanded by large load users to under-write baseload contracts for them (especially those with baseload load profiles).

ii. Supply can be constrained by maintenance outages, unexpected generation or transmission outages, or fuel availability.

(c) Intermittent generation:

i. Demand is again multifaceted. Gentailers use their own intermittent generation to cover their load, but capacity is also demanded by large electricity users for PPAs.

ii. Supply is limited by the fuel availability of wind and sun. Also affected by outages.

(d) Batteries:

i. Demand – gentailers are also using batteries as part of their internal portfolio.

ii. Supply is constrained by charging requirements, and from how many hours it can discharge for (ie, battery size). There are also limitations on discharging due to battery degradation.

(e) Demand response:

i. Demand for this physical capacity is shared by gentailers (for use to manage their risks including dry year risk and capacity risk), retailers, intermittent generation owners for firming, and distributors to manage transmission constraints.

ii. Supply is also constrained by the ability of the load to turn off (by how much and for how long, and with how much flexibility), or in the case of mass market consumers, current culture and willingness.[46] But the New

[46] As discussed in MDAG.

Zealand electricity industry is only perhaps beginning to try and tap into this capacity.

6.6. In responses to our information request, the gentailers discussed the constraints faced by their generation capacity for selling OTC contracts. Contact said this the most explicitly: “We aim to support requests for risk management products, however, our capacity is not unlimited. Our generation portfolio contains limited flexibility and an increasing wholesale market risk/volatility coupled with ongoing risk of fuel availability.” Contact said that shape contracts are largely provided by them from their natural gas generators, but that while gas is typically contracted on mid-term arrangements, it “is exposed to field performance risk and market re-pricing risk at end of contractual term.” It also said that it is currently difficult to get certainty on any new longer-term gas purchase agreements past 2025. In addition, Contact said that selling products covering only winter morning and/or evening peak products can potentially block it from selling what to it is “more desirable” profiles (such as long-term baseload contracts or long-term FPVV contracts), due to capacity constraints. We discuss the impact of scarcity on risk management in chapter 3, and the potential impact of this scarcity on the availability of OTC products is discussed in chapter 5.

But gentailers are working to increase both flexible and baseload supply

6.7. Gentailers are currently the only suppliers of flexible generation,[47] and also own the vast majority of baseload generation.[48]

6.8. However, they are doing a lot of work to increase flexible and baseload supply (and are providing options for contracting of this generation):

(a) Contact – investing in new geothermal generation,[49] investing in batteries including putting out an expression of interest for contracts under-written by a second battery, and attempting to get more flexibility and capacity at its Clutha river hydro stations by proposing changes to its resource consents.[50] It also recently signed a long-term contract with NZ Steel which excludes electricity supply to NZ Steel during morning and evening peaks during the winter, and it included demand response with Tiwai in its latest contract. It has also recently

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47 This includes Nova, who owns two 100MW thermal generators, and Manawa who owns some small-scale hydro generation with some storage. However, Contact recently announced it will be fully acquiring Manawa (subject to Commerce Commission, shareholder, and court approvals). Contact said that ““With our diversified, and complementary, portfolio across the North and South Islands this proposal will enable Contact to sell larger volumes of fixed price electricity contracts over longer periods into the wholesale market.”

48 There is some small-scale run-of-river hydro owned by other participants, but this makes up only around 11% of overall baseload generation.

49 Tauhara was commissioned this year and Te Huka is scheduled for completion later this year. It also has an additional 285MW of geothermal development in its pipeline (Te Mihi stage 2 and Tauhara stage 2).

50 As part of the new Fast Track Approvals Bill, it has proposed some consent variations to the Clutha river scheme to achieve more flexibility and capacity for its operations. It has applied for changes at Lake Hawea, Clyde, and Roxburgh.

launched its “Hot Water Sorter” product.[51] This will see Contact switch off hot water cylinders during times of the day when there is high demand. It aims to have 20,000 customers on this plan by the middle of next year. As of August 2024, it had 6,200 customers on this plan.[52]

(b) Genesis – has made upgrades at Huntly that have resulted in more flexible use of the units. It also has battery investment in its pipeline to cover the start-up times of certain Huntly units depending on whether the unit is cold or warm (ie, making the combined battery-thermal unit a flexible generation option). Its latest iteration of contracts for which participants were invited to bid for (Huntly firming options or HFOs) have greater flexibility in them compared to its last set of contracts (Market Security Options).[53] It is also trialling hot water demand response.[54]

(c) Mercury – has long-term plans to get more capacity out of the Waikato scheme. Mercury also put forward a grid scale battery near Whakamaru for fast track resource consenting, although it was not selected for inclusion in the fast-track Bill. It will instead be considered through the standard resource consenting process, with Mercury aiming to lodge a consent application by the end of the year.[55]

(d) Meridian – has been working to maximise the peaking capacity of its existing hydro generation, including unit capacity increases at both Benmore and Manapouri.[56] Its demand response agreement with Tiwai also increases capacity in the market, both at times of low hydro storage and at peak demand times. It is also investigating aggregated mass market demand response as a risk management option. It has trials underway and development underway for behind-the-meter controlled electric vehicle charging. It is also investigating whether it can expand this to enable consumer demand response from hot water heating (over and above network ripple control uses) and any other device with data feed and connectivity that enables control. It expects “scale to quickly become meaningful, for example

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51 https://contact.co.nz/aboutus/media-centre/2024/04/10/contact-empowers-kiwis

52 https://www.energynews.co.nz/news/demand-response/165593/contact-says-kiwis-are-flocking-tou-plans

53 See https://media.genesisenergy.co.nz/genesis/investor/2022/Genesis_Market_Security_Options.pdf

and https://media.genesisenergy.co.nz/genesis/investor/2024/genesis_huntly_firming_options.pdf

54 https://www.energynews.co.nz/news/electricity/166542/genesis-trials-hot-water-control-new-flex-service?utm_source=newsletter&utm_medium=email&utm_campaign=energy-news-newsletter

55 https://www.energynews.co.nz/news/fast-track-process/168735/three-big-energy-projects-missed-out-fast-track

56 See: https://www.meridianenergy.co.nz/news-and-events/capacity-at-manapouri-power-station-update, https://www.meridianenergy.co.nz/news-and-events/benmore-power-station-unit-capacity-update, https://www.meridianenergy.co.nz/news-and-events/potential-increase-to-maximum-unit-capacity-at-manapouri-power-station, https://www.meridianenergy.co.nz/news-and-events/increase-to-maximum-station-capacity-at-benmore-power-station.

1000 chargers could enable up to 7MW of flexibility that Meridian could use to manage wholesale price risk over peaks".

6.9. All four gentailers are also investing in intermittent generation which may enable them to keep their hydro storage higher and thus be available at greater capacity more often for providing peaking and firming.[57] Investing in intermittent generation does, however, also increase demand on their flexible generation to firm their own new intermittent generation. The more intermittent generation there is in the system, the more flexible capacity is required to firm it.

And there is other activity that will increase supply

6.10. There are some independent developers investing in new intermittent generation. In the 2023 investment survey, the proportion of projects being developed by independent investors was 28%.[58] This will increase the number of suppliers (and volume) of PPAs – although gentailers (as the owners of flexible generation) will still be needed to firm these PPAs (if the PPAs need to be firmed, which depends on the load profile of the buyer). Or alternatively, large electricity users or retailers could enter generation following PPAs with demand response capacity or with flat profiles that match solar generation.

6.11. There are also other options to increase the supply of risk management products:

(a) Batteries – gentailers are already investing in these. But our modelling (and some participants we have talked to) suggests that these are not yet economic for non-integrated retailers to invest in for risk management alone. However, they may become more economic in the future as the energy market changes and increased participation opportunities in the ancillary services markets become available. Our modelling also suggests that a retailer could benefit from a battery when used alongside baseload hedges (giving a similar level of risk reduction to baseload hedges with super-peak hedges).

(b) Demand response – most retailers are already investing in demand response options. More participants expanding this capacity constrains the ability of gentailers to exercise market power. As mentioned above however, there are currently constraints on the ability to expand this capacity. But where possible this capacity should be maximised as an alternative to flexible generation.

(c) TOU pricing – similar to demand response, retailers can expand capacity for risk management by offering different retail tariffs. However, viability will depend on the existence of customers willing to take on spot price risks themselves and either ride through the volatility of spot prices or alter their behaviour to avoid high price periods.

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57 This depends on generation investment compared to demand growth.

58 https://www.ea.govt.nz/news/general-news/generation-investment-data-and-dashboard-now-and-in-the-future/

(d) VPPs – there is some investment happening but it is a developing area of investment. Those VPPs that are in operation do not signal their flexibility in the wholesale market. The Authority has recently implemented some Code changes that should improve the viability of operating VPPs (DNL and DNG).

Chapter 5: Availability and pricing of OTC contracts

1. Contents

1. Purpose

1.1. This chapter presents our preliminary findings on the availability and pricing of OTC contracts. We use data received that relates to requests for contracts between Q4 2022 and Q2 2024. We use data received from non-integrated retailers who had more than 1,000 ICPs as at 30 October 2023, and data received from the gentailers from our section 46 request.

2. Preliminary findings

The most requested contract type is for super-peaks, but baseload and peak are also commonly requested

2.1. Requests for super-peak[1] contracts were the most commonly requested contract type over the time period we have data for. However, baseload and peak contracts are also requested often. Other – more bespoke – contract types are not requested often.

2.2. Requests are most commonly sent out around 10 months in advance and are usually for shorter duration contracts (less than one year in duration). This may be because longer duration contracts carry more risk (for both parties).

OTC contracts are available and traded but for some products there is limited volume

2.3. Almost all requests (over 99%) received at least one offer. However, the OTC market is not very deep:

(a) Super-peak contract requests (those that are impacted the most by capacity scarcity) received fewer offers per request

(b) Around a third of all offers received were for less volume than requested

(c) All offers received for super-peak contract requests were from gentailers (no other participant types responded to such requests)

(d) Around half of all requests resulted in a trade

2.4. Uncertain or scarce fuel supply and prudent security of supply positions are used as justifications and likely to contribute to the risk aversion shown by some gentailers when responding to RFPs (although we cannot form a definitive conclusion on these being the main drivers of all refusals from gentailer documentation that we have access to).

[1] Super-peak contracts cover the morning and/or evening peak trading periods. These are defined in detail in paragraph 3.5

Prices for baseload and peak OTC contracts appear to be competitive, but we can't rule out super-peak prices being non-competitive

2.5. Our analysis suggests that prices offered for baseload and peak contracts are competitive. When we compare prices for OTC contracts to our estimated competitive prices (using ASX baseload prices and adding estimated risk premia, discussed in section 6), they are similar, although there does appear to be a slightly increasing trend in baseload offer prices.

2.6. A high proportion of traded baseload hedges were conforming offers, and prices were often comparable to ASX prices. This suggests access to baseload hedges is not inhibited by the difficulty and cost of trading on the ASX.

2.7. However, there appears to be an increasing trend in super-peak prices over time (relative to ASX baseload prices). When we add a shape premium to ASX prices, super-peak prices are sometimes still substantially higher. Offer prices for super-peak contracts could be consistent with a lack of competition, or simply reflect scarcity. Reasons for this uncertainty include:

(a) There have been some accepted prices that were substantially higher than ASX prices (plus shape premium). This could be because the contract was competitively priced, or because the buyer had no other viable alternative

(b) Our risk premia are based on historical data, but these should ideally be forward-looking. There is also uncertainty around how risk premia will change in the future.

(c) We have been unable to estimate other premia (eg, premia for scarcity, volatility, and illiquidity) that could have a big impact on super-peak contract prices (and are likely increasing)[2]

(d) Super-peak contracts transfer more risk to gentailers than other contract types, and no other participants are offering them. Depending on how this risk fits with the gentailer's portfolio, this could be more or less costly for them. For example, selling contracts for generation capacity during super-peak periods constrains them from selling contracts that cover more trading periods, which may fit better with a portfolio containing baseload or hydro generation.

(e) Gentailers are providing other products for super-peak times which may fit better into their portfolios (Genesis's Huntly Firming Options and Contact's virtual battery services and battery cap products).

We have found no evidence of unjustifiable discrimination in the pricing of OTC contracts

2.8. We found no evidence to suggest that there is any discrimination in the pricing of contracts. Prices traded with other participant types (eg, other gentailers) fall within the range of prices traded with NIRs. While some of these prices offered to other customer types are towards the lower end of the range, there are justifiable reasons for this (such as contract duration, or a flatter and more predictable load profile for

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[2] See Appendix A for more detail.

FPVV contracts, or the industrial customer being able to provide demand response).

NIRs with smaller balance sheets find it harder to meet OTC contract credit limits

2.9. Smaller NIRs likely face barriers to participation in the OTC market due to having smaller balance sheets. This means they receive a lower credit rating. However, this is a rational business decision on the part of the counterparty that is selling contracted volume.

3. The data classification and analysis in this report follows the approach outlined in the OTC Code of Conduct Monitoring

3.1. This section contains a brief overview of the OTC data we received, and how we classified and analysed it.

About the data we have received and analysed

3.2. We received data from all NIRs with ICP numbers above 1,000 (as at 30 October 2023) on their OTC requests sent, offers received, and trades made. We also received data from gentailers on OTC contracts signed with other participants.[3]

3.3. The data excludes requests that:

(a) Had a response time of less than one day

(b) Were for a transaction of less than 1MW; or

(c) Were a non-written request.

3.4. For this review, we are mainly interested in the responses NIRs received to requests to buy contracts, so here we have excluded requests by the NIRs to sell contracts.

Contracts were classified based on their type and the time periods to which they apply

3.5. OTC contracts can have any structure. To enable analysis of the raw data, we have split contracts into 5 types (note that these can differ from ASX products):

(a) **Cap** – request is for a maximum (capped / 'strike') price to pay for electricity, generally for an agreed fixed volume[4]

(b) **Baseload** – ie, volume requested for all trading periods (for either business days only, or for all days). This is the same product that is available on the ASX.

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3 Data was received from Genesis, Contact, Meridian and Mercury.

4 Note that these contracts can have different strike prices.

(c) **Peak** – ie, volume requested within the period from 6am to 11pm (this product is also available on the ASX for 7am to 10pm, although is not market-made[5], so has lower volumes transacted)

(d) **Super-peak** – volume is requested within the morning or evening peaks (exact times requested can differ, but usually include 6am to 10am, and 5pm to 11pm)

(e) **4-hourly** – a different amount of volume is requested for each 4-hourly block in a day (can also be different volumes requested for business days compared to non-business days)

(f) **Other** – any contracts requested that do not fall into the above categories

We treat requests for different contract attributes as individual requests

3.6. Contracts can have different attributes (eg, different location, duration, trading periods, or volume). If a written RFP is sent out that includes more than one request with differences in any of these attributes, we treat these as multiple contract requests according to the guidance we sent out.

We classify offers based on whether they match the exact terms of the request

3.7. We have classified offers to requests as either conforming or non-conforming:

(a) A **conforming offer** means that the respondent responded with an offer that was exactly the same as that requested (ie, the same volume, location, shape, duration, and time period).

(b) A **nonconforming offer** may differ from the request in any of these respects.

3.8. If a request receives an offer (conforming or nonconforming), the requestor can accept that offer, accept a different offer (if there are more than one) or not accept any offer.

3.9. As described in paragraph 3.6, RFPs asking for multiple products with different attributes were split into multiple contract requests. Occasionally it became ambiguous as to which response corresponded to which contract request. In cases where this was ambiguous, responses were matched to the request with the closest attributes. Only 27 responses were matched to a request in this way. This matching was done to ensure no responses would be discounted, and each response would only correspond to one individual request.[6] However, one request may have received multiple responses from the same respondent. If a response was filled out with an offered price and all the relevant attributes, we interpreted this as the respondent being interested in making an offer.

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5 Four gentailers and one commercial market maker currently support trading of hedge products on the ASX. These parties post prices at which they are willing to both buy and sell such products during a half hour trading window each trading day. They are called ‘market makers’, and their activity is called ‘market making’.

6 We understand from one gentailer that sometimes a single offer could be made in response to all of the contract requests within an RFP. Here we have only matched a single offer to one of the contract requests within an RFP.

A nonconforming offer may signal negotiation

3.10. We are using ‘conforming’ and ‘nonconforming’ as neutral descriptions in this analysis.

3.11. A ‘nonconforming’ offer does not necessarily mean that an offer is not useful, or that it is a sign of misconduct. It means that a respondent did not offer exactly what was requested, which could be for various reasons. Over a third of all OTC trades made by non-integrated retailers were from nonconforming offers.

4. Availability of OTC contracts

Super-peak has been the most requested and the most traded type of contract

4.1. Super-peak contracts have been the most requested contract type over the time period we have data for.[7] More bespoke contracts, like Cap and 4-hourly are requested less often.

4.2. It is not surprising that super-peak requests have been the most commonly requested by non-integrated retailers. Super-peak contracts cover the trading period when the residential demand of these retailers is the highest, as well as when the wholesale price of electricity is the most volatile. However, the recent high wholesale prices in July and August 2024 highlight the need for other contract types (covering periods outside the super-peak trading periods) as well.

4.3. There is no apparent trend to the total volume requested by quarter, over all shorter duration requests (contracts of one year or less, which were more commonly requested than longer duration contracts). Note that while longer duration contracts are much less frequently requested, the total volume requested for longer duration contract types is much greater than that of shorter duration, because the contracts are for longer periods of time.

Almost all requests received at least one offer, and more than half of super-peak requests received at least one conforming offer

4.4. Over 99% of all requests received at least one offer. Baseload requests almost always received at least one conforming offer while peak requests had a slightly lower rate and super-peak requests the lowest rate. Around half the time super-peak requests received at least one conforming offer.

4.5. That super peak requests had a lower rate of conforming offers than baseload and peak requests is not surprising, as these requests are for periods when spot prices are likely to be highest and when capacity is most constrained.

4.6. It is less common for requests to get more than one conforming offer. However, receiving one nonconforming offer doesn’t mean that respondents had no choice between offers. For a small proportion of all requests that resulted in a trade, requestors accepted a nonconforming offer over a conforming one.

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7 Note that we treat requests for morning and evening peaks separately. However, if these are combined, our conclusions remain the same.

The number of offers per request for baseload and peak contracts has increased over time although decreased in the most recent quarters for baseload

4.7. The number of offers received per request increased overall for baseload and peak contracts between 2022 Q4 and 2023 Q3, but then decreased slightly for baseload requests between 2023 Q4 and 2024 Q2. This could be due to the energy scarcity seen at this time. We will continue to monitor whether offer rates increase in the later quarters of 2024 after significant inflows to the hydro lakes occurred in 2024 Q3.

4.8. Offers per request for super-peak contracts are fairly consistent over the quarters we have data for, but usually (in all except one quarter) lower than the offer rate received for baseload and peak contracts.

There are not many participants able to respond to super-peak requests

4.9. Super-peak contracts are the most commonly requested and traded, but have the lowest rate of offers. We consider it likely that (usually) the maximum number of respondents to super-peak requests is three.[8] Genesis's Rankines and Huntly 5[9] take time to warm up, and Huntly 6[10] does not have large capacity (50MW).[11] While Genesis may therefore not offer for OTC super-peak contracts, it is selling hedges via its Huntly Firming Options, which include contract types to cover super-peaks (albeit under the limitations imposed by operation of the rankines). That leaves three gentailers with portfolios able to under-write super-peak requests. We discuss more below on how portfolios may impact on offers.

Around half of all requests resulted in a trade

4.10. Overall, around half of all requests resulted in a trade. But the proportion of trades differed by contract type. Peak requests had a slightly higher proportion which resulted in a trade, while baseload and super-peak were similar.

4.11. Of the requests that resulted in an accepted offer, over half were from conforming offers. However, there has been an increase in the proportion of volumes traded that were from nonconforming offers in 2024.

4.12. Occasionally multiple offers were accepted for one request.

OTC market trades appear to have been affected by energy scarcity in 2024

4.13. In the most recent quarters of data (Q1 and Q2 2024), we have noticed that:

(a) Response rates to requests for baseload contracts decreased

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8 While speculators may respond with offers for super-peak requests, we have not observed this in the data. Manawa has baseload generation (and intermittent generation), and Nova has small capacity (100MW).

9 Huntly 5 (also known as e3p) is a combined cycle gas turbine that runs on gas, the three Rankine units can run on coal and/or gas.

10 Huntly 6 is an open cycle gas turbine. It can run on diesel or gas and is used as a Peaker.

11 Genesis also owns Tekapo hydro stations, but capacity of these stations is small (190MW).

(b) There were changes in how long in advance of the contract start date requests were sent out in Q2 2024, compared to previous quarters. For example, baseload contract requests were sent out closer to the start date

(c) There was an increase in the volume of contracts traded that were from non-conforming offers.

4.14. These changes could be due to the energy scarcity conditions in 2024, where hydro lake storage became low, and there were constraints on the supply of natural gas. We will continue to monitor in future quarters of data we receive whether these statistics change in response to the easing of energy scarcity that occurred at the end of August 2024.

5. Generation portfolios impact on availability and pricing

5.1. As discussed in chapter 4, under-writing a contract of any length usually requires suitable generation capacity for the shape of the contract, and fuel. If a contract seller does not have enough of either of these, it will likely need to fulfil the contract by purchasing from the wholesale market. Capacity that is flexible enough to back a shaped contract is also used to firm intermittent generation (generators may plan to use flexible capacity to firm their own intermittent generation, rather than for backing shaped OTC contracts). Capacity is also affected by outages. Before making a contract offer, generators must decide whether their generation portfolio has the capacity to fulfil it, and how large any associated risks (eg, fuel and outages), as these will affect the price they offer at.

5.2. Uncertainty around fuel in the period being requested is likely to impact thermal and hydro generators' propensities to offer. This was evident in winter 2024 when hydro storage was low and less gas was available.

6. Assessing the competitiveness of OTC prices

6.1. This section aims to assess whether the OTC contract prices received are consistent with competitive outcomes. To investigate this, we compare OTC prices received to ASX prices. We also look at the OTC prices for similar trades between different types of participants.

6.2. We have found that ASX prices are unbiased forecasts of spot prices under expected market conditions (refer to appendix A, suggesting that ASX prices are competitive). We can therefore compare OTC contract prices to ASX prices to get an indication of whether OTC prices are competitive.

6.3. If OTC contracts are competitive, we would expect that similar products on the OTC and ASX market have a similar price distribution. We would expect other OTC products (eg, peak and super-peak) which are not market-made on the ASX to have higher prices due to the nature of the contracts (eg, higher average spot prices during these times, higher spot price volatility). We would also expect a divergence if the risk premium of these contracts increased relative to the risk premium of

baseload contracts (eg, if the volatility in super-peak prices was increasing at a faster rate compared to volatility in off-peak times).[12]

6.4. For our analysis, we first compare the OTC prices against quarterly ASX baseload contract prices.[13]

6.5. We then add estimated premia to the ASX prices. The premia were estimated based on wholesale spot prices:[14]

(a) Location premia were added to ASX prices, when applicable. Those premia were calculated as the difference between the offers' location and the relevant ASX node (Ōtāhuhu for offers made for the North Island and Benmore for offers made for the South Island).

(b) ASX prices for comparison to peak products were multiplied by the ratio between the 2019-2023 average spot prices during peak times (between 7am and 10pm) and the 2019-2023 average baseload spot prices.

(c) ASX prices for comparison to super-peak products were multiplied by the ratio between the 2019-2023 average spot prices during super-peak times (combining morning and evening times: 7am to 9am and 5pm to 9pm) and the 2019-2023 average baseload spot prices.

Offers for baseload products

6.6. The data shows that OTC baseload offer prices have been comparable to ASX baseload prices. It also shows that accepted offers tend to be closer to the ASX prices compared to prices that were not accepted. Requests with no offers accepted often (but not always) showed the highest deviation from the ASX, with a few offers priced considerably above the ASX. There was a slightly increasing trend in offer prices for baseload products over the time period we have data for.

6.7. We also compared OTC offer prices for baseload products to the ASX baseload prices updated using our estimates for location premia. There were only subtle changes when comparing the results to the ones discussed above. This is mainly because most of the contracts (around 90%) were requested for either Ōtāhuhu or Benmore (thus no location premium was added). Additionally, the average difference between nodes is relatively small.

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12 Refer to appendix A for a discussion of risk premia.

13 We match NI nodes to Ōtāhuhu and SI nodes to Benmore and use the ASX quarters corresponding to the quarters within which the OTC contracts fall. If an OTC contract spans more than one quarter, we take the average of the ASX quarterly prices.

14 This is done by quarter. See Appendix A for details.

Peak offers

6.8. The data shows that peak products are usually offered at higher prices relative to baseload products, as expected for a shaped product. Offer prices for peak contracts did not appear to be increasing over the time period we have data for (relative to ASX baseload prices).

6.9. When we added our estimates for premia to the ASX baseload prices, we found that some of the accepted offers were lower than the adjusted ASX prices, while some were still higher. We note in appendix A that we have not included some risk premia that we think would be added in a competitive market (due to estimation complexities). Therefore, these ratios would be even lower if we included more risk premia.

Super-peak offers

6.10. The data shows that super-peak products are mostly offered at higher prices compared to ASX baseload products (and often higher than for peak products). Since super-peak products fall within trading periods with the highest spot prices, having a premium over baseload products is expected. The relationship between offer prices and offers being accepted is less evident for super-peak products, with some higher priced offers being accepted. This indicates that other factors might have a strong weight in the NIRs' decision-making for procuring super-peak products.

6.11. As with baseload contracts, there was an increasing trend in super-peak offer prices (relative to ASX baseload prices) over the time period we have data for. This trend was stronger than for baseload offer prices.

6.12. We also compared the OTC offer prices for super-peak products to the ASX baseload prices updated incorporating our estimates for premia. The results indicate that the accepted offers are still mostly above the ASX prices, even after including the premia.

6.13. The upward trend in super-peak offer prices is still visible when the risk premia are included, which might reflect market conditions, with declining hydro storage and limited gas availability from Q3 2023 to Q2 2024. We have not included any additional premium for scarcity (which may impact super-peak prices more than baseload prices) in our estimates, due to the complexity of estimating these.[15]

OTC trades made between gentailers and other customer types are within the range of prices they offer to NIRs, although on the lower end

6.14. We also looked at how the offers made to NIRs compare against the hedge contracts signed between gentailers and other parties, such as large consumers, small and large generators, and other gentailers. Here we restrict our analysis to Contracts for Difference (CfDs), excluding FPVVs with commercial and industrial customers. FPVV contracts are covered in the following section. When applicable we make a distinction between contracts valid for less than a month (or 28 days) from those valid over a month (more than 28 days).

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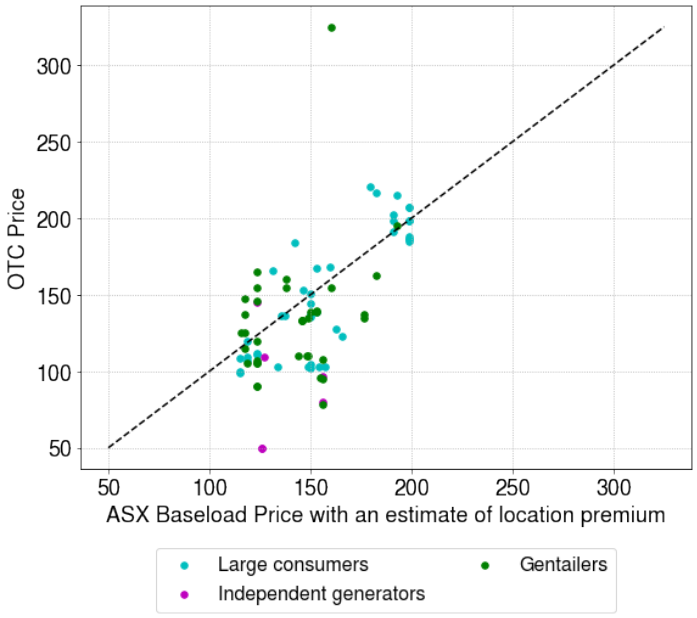
[15] See Appendix A for more detail.

6.15. Most of the signed CfDs between gentailers and other parties are of baseload type and are often signed between either a gentailer and a large customer or between gentailers, as shown in Figure 1. It also shows that those contracts tend to be priced close, and often lower, than the ASX baseload prices (including location premia).

Figure 1: OTC baseload contracts signed between gentailers and other parties



6.16. When comparing the OTC offers accepted by the NIRs to the contracts signed between gentailers and other parties, most of the prices appear to be comparable. A few of the contracts, however, are priced in a price region below the prices usually accepted by NIRs. The lowest priced contracts are usually less than 28 days in duration, however there are quite a few contracts of greater than 28 days duration that are also lower than contracts signed with NIRs.

6.17. For peak and super-peak products, there were considerably fewer contracts signed between gentailers and other parties. For peak products, the other party was always another gentailer. The prices of contracts signed between gentailers are often close to the ASX baseload prices (including shape and location premia) and are often contracts with shorter duration, compared to the offers accepted by NIRs. The few similar duration products traded at similar times have a comparable range of prices for both gentailers and NIRs.

6.18. A few contracts signed between gentailers were priced higher than most of the offers accepted by the retailers. In two cases, contracts between gentailers were priced considerably lower than the offers accepted by non-integrated retailers. These contracts were valid for one day and were referenced to the spot price – spot prices at that time were low due to high storage levels. Most contracts between gentailers and other parties for peak products were within the range of contract prices traded with NIRs.

6.19. There was only one OTC super-peak contract signed between gentailers during the period of analysis, and it is priced lower compared to many of the prices accepted

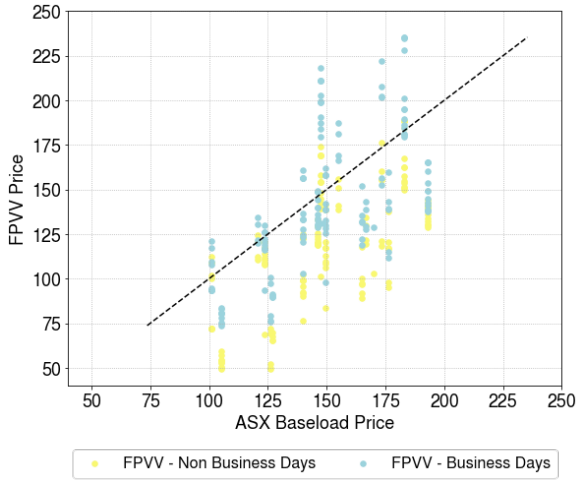
by NIRs. It was, however, for a shorter duration than the super-peak contracts with NIRs.

Gentailers add lower margins to FPVV contracts with C&I customers, but there may be valid reasons for this

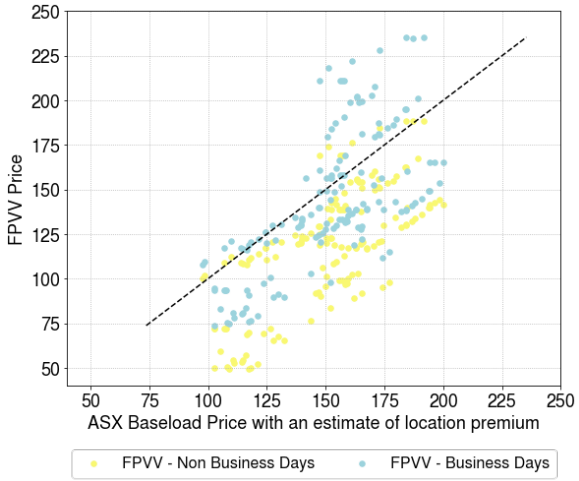
6.20. Figure 2 shows the FPVV contract prices compared to the ASX baseload prices (with and without location premium).[16] FPVV prices are comparable to ASX baseload prices. The lower-priced FPVV contracts are usually for non-business days, as expected (as spot prices are lower during non-business days).

Figure 2:FPVV contracts versus ASX baseload prices

A - FPVV signed contract prices and ASX prices



B - FPVV signed contract prices and ASX prices (with premia)



6.21. We asked gentailers to provide information on their pricing methodologies, and to provide some examples where they apply this methodology (one example per contract type).

6.22. In general, we found that gentailers have a similar approach in pricing requests for both OTCs and FPVV for retailers and C&I customers, which was

```
Reference price x location factor x shape factors x (1+margin)
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6.23. The reference price is usually based on the current ASX prices, unless the time period went beyond the current ASX curve, in which case most gentailers used their internal estimates of longer term prices. Some gentailers also considered their expected short run marginal cost given their portfolio position to price contracts.

6.24. The location and shape factor adjust the prices depending on the contract requested and/or the load profile of the customer. Some gentailers preferred to offer contracts at a specific node to reduce load factor risks.

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16 We collected information on each gentailers' ten largest (where size is based on GWh/year) FPVV contracts signed over the period 1 November 2022 to 31 December 2023.

6.25. The margin is also added to cover any further cost associated with holding the OTC or FPVV. In particular, if gentailers expected to back a contract with an ASX trade they would include the risk of the ASX price changing between offering the price and backing an accepted contract, as well as the cost of holding that ASX position to term.

6.26. From the working examples provided for OTC contracts for non-integrated retailers, the additional margin ranged from 0 to 10%, with the lowest margins (including 0%) used when the OTC request fit well into the gentailers existing portfolio and therefore did not require additional trading on the ASX. Some gentailers stated that if a request did not fit well within its current portfolio, it would offer a contract which did fit well, for example pricing a baseload contract when a peak contract was requested.

6.27. Margins between 4 and 10% were added to OTC prices where the gentailer expected to back the contract on the ASX. Genesis stated they always backed OTC contracts with ASX trades. The margins were highest when the amount of MW requested was high. The stated reason for this by gentailers was that it could take several days of trading to back a position for a large contract, and therefore there was higher risk of price changes. Gentailers often offered several tranches in this later case, with a higher price as quantity covered increased.

6.28. We checked whether these margins were consistent with ASX volatility, and found that they were sometimes slightly higher than the average weekly range in ASX prices (although our estimates are based on average historical values). This is discussed in more detail in Appendix A.

6.29. For FPVV trades, the additional margin ranged from -5% to 2.4%. A negative margin implies they were selling FPVV at a price lower than what they would receive from an equivalent trade on the ASX market.

6.30. Gentailers provided a couple of reasons for offering lower and negative margins to FPVV. One was that it prevented them from needing to trade the position on the ASX (ie, the reverse reason for adding a margin to OTC contracts). This implies that these FPVV were for load which the gentailer was already factoring into their portfolio position. This would likely apply to renewals of existing FPVVs. Contracts with C&I customers may also carry less risk for gentailers due to a more predictable load profile, and in aggregate, a flatter load profile. Meridian said that “While retail sales are often for a variable volume that is subject to change at any time, the risk is manageable as consumption volumes can be readily estimated based on the nature of a customer, their historic consumption, and expected activities at an ICP.”

6.31. The second was that there was some other value for the gentailer in winning or retaining a consumer by offering them an attractive FPVV. Reasons given included:

(a) The C&I customer does or expects to be able to provide demand response in the future (including process heat demand conversions – ie, growing a gentailers flexible customer base).

(b) The gentailer can build brand value

(c) The gentailer can develop long-term strategic relationships (ie, future contracting opportunities with large customers)

6.32. The contract process for an FPVV gives C&I customers an opportunity to negotiate a better price then the first offer, while the RFP process for small retailers does not appear to provide this (at least for larger contracts with written RFPs).

6.33. Overall, it appears that C&I customers do get better prices compared to non-integrated retailers due to a smaller or even negative margin being added to requested prices (although prices are similar to ASX prices). However, at a general level there appear to be some valid reasons for this. An aggregate flatter (and more predictable) load profile, potential for demand response and future electrification we think are rational reasons for reducing margins. There are also caveats to our findings - the provided datasets were small and the requests from small retailers and C&I are not equivalent. On this basis we have not sought to validate whether the level of difference between the margins is justified. Once the new hedge disclosure obligations are implemented we will have more data with which to continue monitoring FPVV prices against other contract prices.

7. NIRs with smaller balance sheets may find credit policies and assessments a barrier

7.1. Before signing an OTC contract to sell volume to a counterparty, respondents will assess the credit risk of the counterparty (the probability that the counterparty will not be able to pay their obligation), and the credit limit that they will apply to any trade with that counterparty.

7.2. If respondents assess that the counterparty's credit limit is too low for the trade requested, then they may approve an increase to that limit based on their internal credit risk policies. In this case the counterparty may need to provide additional credit support for the trade, such as a cash bond, a Letter of Credit or Guarantee from a bank (or other organisation, including the counterparty's parent company). They could also choose not to trade with that counterparty, because the risk that they will make a financial loss is too high, or they could offer a trade with a lower credit exposure.

7.3. We collected data from gentailers on their credit policies and credit assessment methodologies. We have analysed these to assess whether there are any non-price[17] barriers for non-integrated retailers engaging in the OTC market.

7.4. We have not found any evidence to suggest that NIRs are treated differently to other types of participants in gentailer's credit assessments and credit policies.

7.5. Credit limits are typically calculated using objective calculations (ie based on information about the buyer's balance sheet). Some discretion may be applied, but examples of this discretion appear to be rational business decisions (ie, criteria including ownership structure of the counterparty, key market risks facing them, previous payment history, whether audited, unprofessionally presented financials etc).

[17] Non-price meaning other than the price per volume of the offered contracts

7.6. Credit risk assessments include credit conduct of the buying counterparty, and/or their current financial position.

7.7. There was also an example of a gentailer providing a non-integrated retailer with a bespoke agreement when requested.

7.8. The lack of a large balance sheet could affect participation in the OTC market of small NIRs (as they may not be able to get a high enough credit rating for the contracts they want).

7.9. There were some examples where gentailers required NIRs to provide cash deposits, or procure a Letter of Credit in order to trade a contract (because the credit exposure of the proposed deal was over the NIR's credit limit with that gentailer). These requirements mean more effort for the non-integrated retailer to complete the trade. But this is a rational business decision on behalf of the gentailer selling the OTC contract, as they are trying to limit the risk that the counterparty is not able to pay them.

8. Our modelling results suggest that alternatives to OTC contracts become more attractive when we add risk premia to contract prices

8.1. We ran our modelling adding a risk premium to our risk neutral contract prices (see Appendix B for more details).

8.2. When we added these premia, we found that generally, the overall risk for portfolios using ASX and OTC contracts increased. It brings the E-CVaR of shaped contract portfolios closer to (although still smaller than) portfolios involving other options (baseload contracts combined with demand response, battery investment, cap contracts, or PPAs).

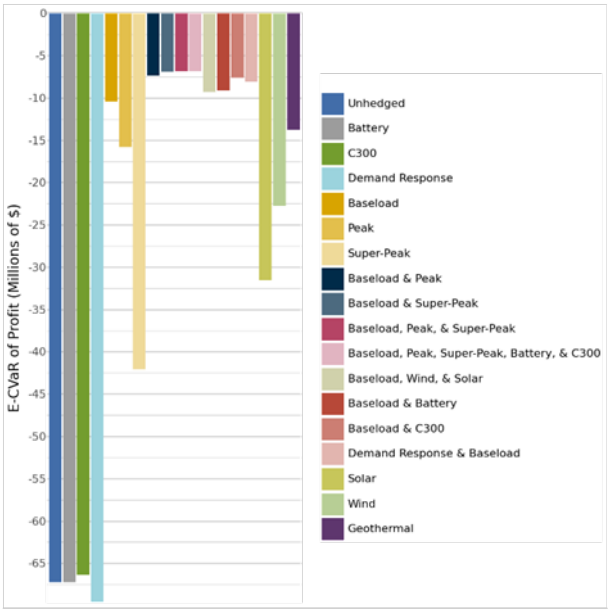
8.3. In our baseline scenario (with no risk premia added), the E-CVaR using baseload contracts alone was the same as using a portfolio of baseload contracts with wind and solar PPAs. When we add a risk premium to the baseload contracts, a retailer now gets some benefit from also buying wind and solar PPAs (on top of baseload contracts), due to buying less baseload contracts because of the premium. This portfolio still does not, however, result in risk reduction as good as the shaped contract portfolios, or the portfolio of demand response and baseload contracts.

8.4. This analysis highlights that it is important to consider risk premia when comparing the risk reduction of different options. If risk premia increase in future, which is highly likely given scarcity in the market to firm intermittent generation and meet peak demand, it is therefore important for retailers to have access to other options to manage their risk. Since we are most likely underestimating risk premia here, it also suggests that other options outside of contracts (eg, demand response, retail tariffs) are already likely to be an important part of portfolios.[18] Additionally, it is

[18] Note that this does not change our assessment of substitutes for market definition purposes, which we based on risk-neutral prices of all options.

likely that the premium during peak periods (and contracts for firming intermittent generation) will increase compared to baseload.[19]

Figure 3: Including seasonal risk premium: Sum of E-CVaR in each island, quarter, and day type given each portfolio



[19] See paragraph 4.7 in Appendix A for a discussion on why.

Chapter 6: How will risk management for retailers change in the future?

Contents

1. Purpose

1.1. This chapter examines how the substitutability of different risk management options is likely to evolve as the economy decarbonises and the electricity market moves towards 100% renewables.

2. Preliminary findings

2.1. As the economy decarbonises and the electricity sector moves towards 100% renewables, it is likely there will be higher price volatility and higher prices at super-peak times. This implies greater price risk for non-integrated retailers and a greater need for risk cover.

2.2. As set out in chapter 4, a portfolio of risk management products is optimal for non-integrated retailers to manage their spot price risk. We found there were some portfolios that are currently – or are expected to be – close substitutes for baseload and super-peak hedges. In this chapter, we look at the results of our future scenario modelling to look at how the expected risk reduction of different portfolios may change for non-integrated retailers in the future.

2.3. Three different modelling scenarios were used to represent likely characteristics of a future with a greater penetration of intermittent generation.[1]

2.4. Comparing different risk management portfolios with a portfolio of baseload and super-peak hedges, we can make the following preliminary findings:[2]

(a) Portfolios of wind or solar PPAs with baseload futures performed slightly worse, indicating these options could become more distant substitutes in the future – not much better than baseload futures on their own;

(b) A portfolio of battery energy storage systems (BESS) and baseload hedges gave mixed results over our future scenarios compared to its current estimated risk reduction, indicating it is not clear whether this option will become an even closer substitute to a portfolio of baseload and super-peak hedges in the future. It did however continue to perform well, so we still consider it to be a close substitute for the future. Just how good this option may be depends on how spot prices and battery technology (and/or financial services based on batteries) may evolve;

(c) The portfolios of demand response with baseload hedges, C300 caps with baseload hedges, and peak hedges with baseload hedges all continued to perform well or slightly better, indicating these options are likely to remain close substitutes for a portfolio of baseload hedges with super-peak hedges in the future.

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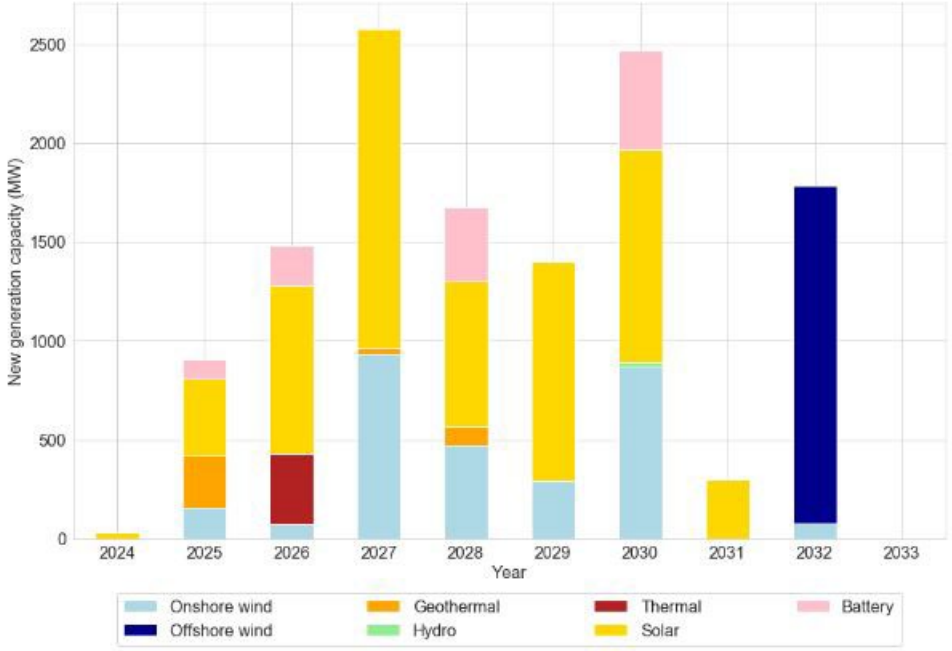
1 For details of the assumptions used for these scenarios, refer to Appendix B.

2 We are assessing performance on the ability to reduce risk—specifically maximising what we call the E-CVaR. This is a hybrid of Expectation Value and Conditional Value at Risk and places a 50% weighting on the expected payoff over all market states and a 50% weighting on the expected payoff over the worst 20% of market states.

3. The transition to renewable generation will lead to higher peak prices and greater price volatility

3.1. The majority of projects in the generation pipeline are wind and solar, supplemented by smaller amounts of geothermal and green thermal. Figure 1 is copied from the system operator's 2024 Security of Supply Assessment and shows proposed new supply project additions by technology and year.[3]

Figure 1: Proposed new supply project additions by technology and year



3.2. Furthermore, some existing thermal generation is likely to retire over the coming decade as rising carbon prices and displacement by new renewable generation make the economics of maintaining and operating fossil generation more challenging. As an example of this, Contact Energy decommissioned its Te Rapa co-generation plant in 2023 and expects to retire its 360 MW Taranaki Combined Cycle plant at the end of 2024.[4]

3.3. Wind and solar, being intermittent, can't be relied upon to contribute greatly to peak capacity, which is driven by residential morning and evening peak demand—the system operator models winter peak contribution factors of 25% for wind and 5% for solar.[5]

3.4. Several BESS are already being developed or planned, which will help to compensate for this reduction in peaking capacity. Nevertheless, under the Security of Supply Assessment's more severe thermal retirement scenarios, it notes that "there are [currently] insufficient potential renewable supply projects to provide the

3 Appendices for Security of Supply Assessment 2024, Version 2, 26 June 2024, Figure 7

4 Contact 2024 Integrated Report, page 32

5 Appendices for Security of Supply Assessment 2024, Version 2, 26 June 2024, Table 5

additional capacity required to maintain the NI-WCM [North Island Winter Capacity Margin] at the lower security standard".[6,8] [7]

3.5. The Security of Supply Assessment also notes that "to bring this renewable supply pipeline to market would require a significant increase in the pace of development".[8] Plant investment and retirement relies on the financial decisions of individual firms. This process can be somewhat irregular. Demand growth can also be irregular with large industrial consumers entering or exiting the market. This uncertainty increases risk for generation developers and can cause them to delay investment decisions, leading to periods where the supply/demand balance becomes more stressed, particularly at peak demand times.

3.6. Furthermore, the economics of BESSs relies on the ability to arbitrage between lower-priced charge periods and higher-priced discharge periods. This implies that a minimum level of intra-day price volatility will endure.

3.7. Exactly how future investment and retirement decisions will play out is uncertain, but three things seem likely:

(a) a reduced ability to meet demand peaks (driven by residential morning and evening demand peaks) leading to a greater likelihood of very high spot prices at these times, and

(b) more volatile prices at all times (with both low and high prices more common), driven by output swings from an ever-larger intermittent generation fleet. The MDAG notes that "As the proportion of intermittent supply increases, it is likely that spot prices will be less correlated with demand and more highly correlated with periods of low intermittent generation in each half-hour."[9]

(c) as thermal generation is progressively displaced, there will be less dry year cover, leading to a greater risk of extended periods of high prices. To counter this, the MDAG hypothesised that hydro lakes will tend to be run fuller leading to a greater likelihood of spill and extended periods of low prices as well. While BESS's will be critical in intra-day firming they (currently) store only a few hours' worth of energy—far too little to contribute to dry-year firming.

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6 North Island Winter Capacity Margin (NI-WCM) is the sum of North Island supply capacity, less the expected peak demand, plus surplus South Island supply capacity able to be sent via the HVDC link to the North Island. The NI-WCM security standard, representing the efficient level, is specified as 630 – 780 MW in Clause 7.3(2) of Part 7 of the Code.

7 Security of Supply Assessment 2024, Version 2, 26 June 2024, Section 4.1

8 Ibid.

9 Price discovery in a renewables-based electricity system: Final recommendations paper, 11 December 2023, paragraph B.28 [this hyperlink doesn't work anymore though the address itself is still valid. Something to do with moving over to SharePoint?]

4. Underlying scarcity increases demand and decreases availability

4.1. The above discussion has highlighted the likely increase in price volatility (over time scales ranging from hours to months) as the transition progresses. This implies greater price risk for non-integrated retailers and a greater appetite for risk cover.

4.2. From the data we have starting in 2022, non-integrated retailers have sought to minimise their exposure to spot prices by seeking to acquire a portfolio of risk products that approximates their expected load profile (eg. baseload, peak and super-peak).

4.3. Some non-integrated retailers have reduced their need for shaped products by managing their customer demand through time-of-use tariffs or demand response products, or seeking customers with a flatter demand profile, as discussed in section 4 of chapter 4.

4.4. To the extent that non-integrated retailers do not (or cannot) manage their customer demand, greater intra-day price volatility implies a continued or even greater demand for shaped risk products.

4.5. However, spot prices also vary over longer time scales of months to years due to changes in such things as fuel availability and hydro inflows. Hence a successful risk management portfolio is likely to also need to include baseload contacts to cover this component.

4.6. As discussed in section 5 of chapter 4, financial risk management contracts are usually underwritten by physical capacity—historically generation but increasingly demand response as well.

4.7. Gentailers also seek to minimise their exposure to spot prices—by matching their generation and demand, supplemented by financial contacts. Since gentailers own most of the flexible generation, as the supply/demand balance becomes shorter, there is less capacity left over to underwrite financial contracts for other parties.

5. Our modelling results suggest portfolios with different products remain good options in our future scenarios

5.1. Chapter 4 identified several risk management portfolios that are currently relatively close substitutes for a portfolio of baseload hedges and super-peak hedges and some that are slightly more distant substitutes. These include:

(a) A portfolio of baseload hedges and peak hedges

(b) A portfolio of baseload hedges and demand response

(c) A portfolio of baseload hedges and retail tariffs[10]

(d) A portfolio of baseload hedges and virtual battery services

(e) A portfolio of baseload hedges and wind or solar PPAs

(f) A portfolio of baseload hedges and C300 caps.[11]

5.2. We wanted to test whether these options are likely to become either more or less effective substitutes in future. The last three modelling scenarios covered in Appendix 2 aim to represent likely characteristics of a future with more intermittent generation and less thermal generation. These are:

(a) more intermittent generation

(b) more volatile spot prices

(c) higher prices at super-peak times

More intermittent generation

5.3. Spot prices tend to be lower in trading periods when intermittent generation is higher. In this scenario, historical spot prices were modified to accentuate this effect to represent a future where wind and solar penetration have increased to 30% and 10% of total generation respectively.

5.4. The modelling for this future scenario indicated that unfirmed (generation following) wind and solar PPAs on their own would be even less effective risk management tools than they are today. In combination with baseload futures, the PPAs were slightly less effective than today—not much better than baseload futures on their own. A BESS in combination with baseload futures was also less effective, though to a lesser extent. This may be expected given our assumed time constraints on battery discharge.[12] Demand response in combination with baseload futures performed about the same, while a C300 cap in combination with baseload futures was slightly more effective (these portfolios are indicated by the red circles in Figure 2).

5.5. The risk reduction from a portfolio of baseload and super-peak hedges remained very effective at reducing risk (as for the current market). This implies that a lot of the higher prices still fall within super-peak periods when intermittent generation is low.

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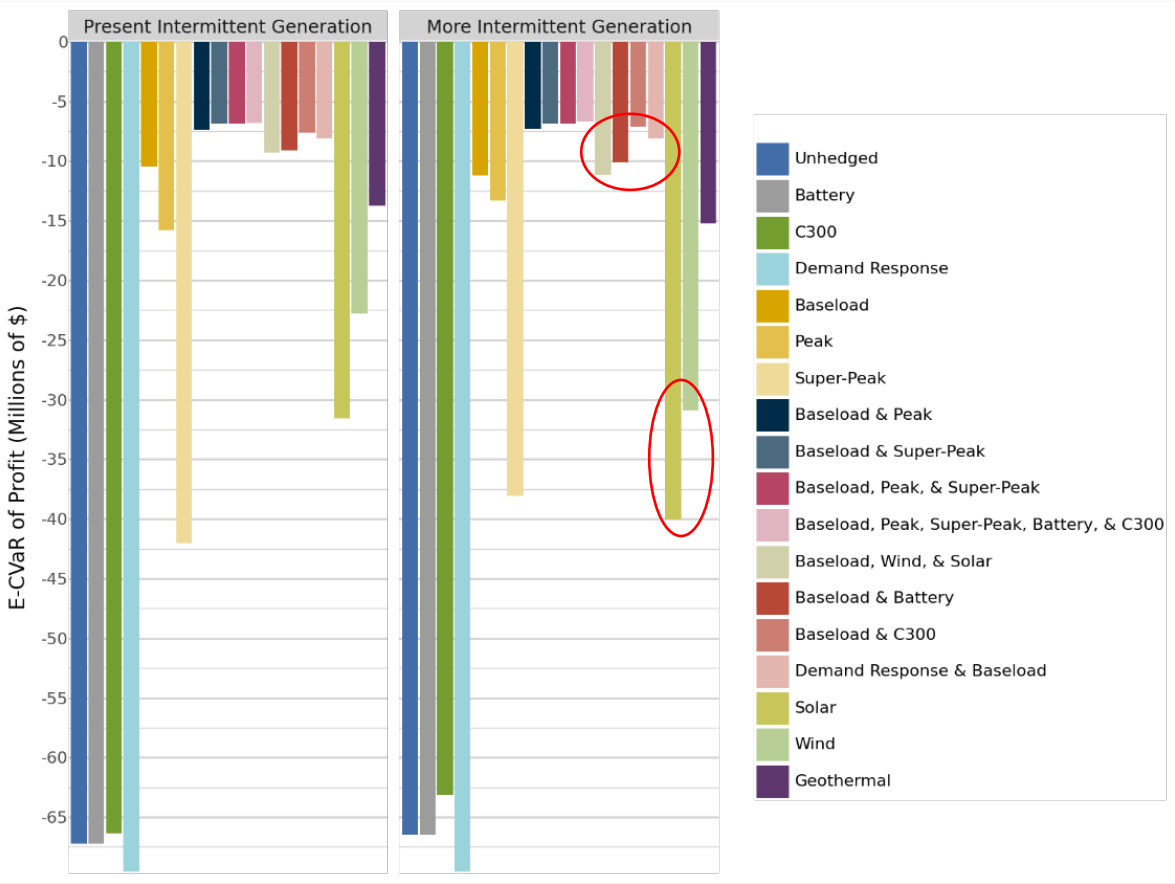
10 We do not model demand response and retail tariffs separately. We model a single regime in which a non-integrated retailer uses retail tariffs to incentivise its customers to shift load from peak to off-peak periods so that the non-integrated retailer's intra-day demand profile is completely flattened. A similar effect could theoretically be achieved by contracting with another party.

11 A portfolio of baseload hedges with PPAs was identified as somewhat more distant substitutes.

12 Our modelling assumes a battery with only two hours of storage, which is typical for current systems

Figure 2: More intermittent generation: Sum of E-CVaR in each island, quarter, and day type by portfolio



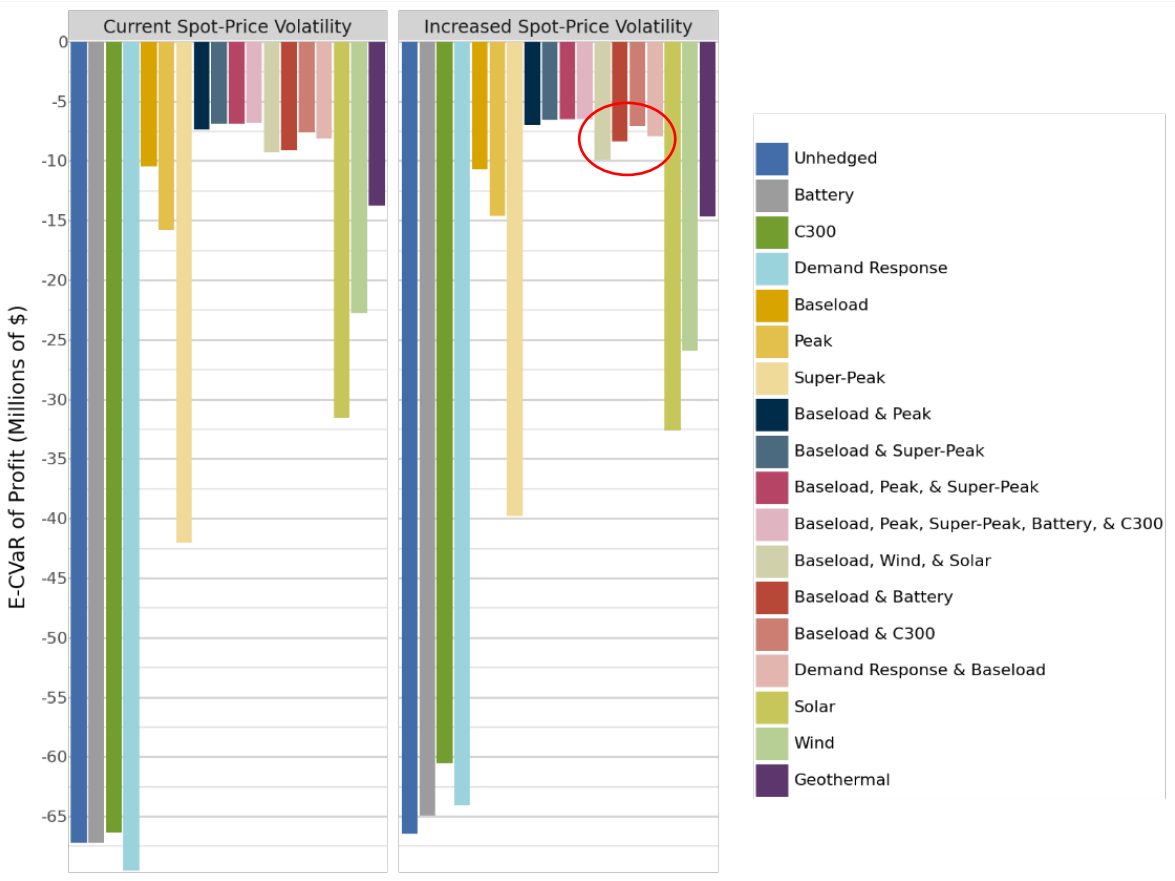
More volatile spot prices

5.6. In this scenario, the standard deviation of the price distribution has been increased while maintaining the mean of the distribution to be approximately the same.[13]

5.7. The modelling indicated that a BESS or C300 cap in combination with baseload futures would be a slightly more effective risk management tool than today, while wind and solar PPAs in combination with baseload futures would be slightly less effective. Demand response in combination with baseload futures performed about the same (Figure 3).

[13] The standard deviation has been increased by between 33% and 100% depending on the market state (refer to Appendix B for details)

Figure 3: Higher spot-price volatility: Sum of E-CVaR in each island, quarter, and day type by portfolio.

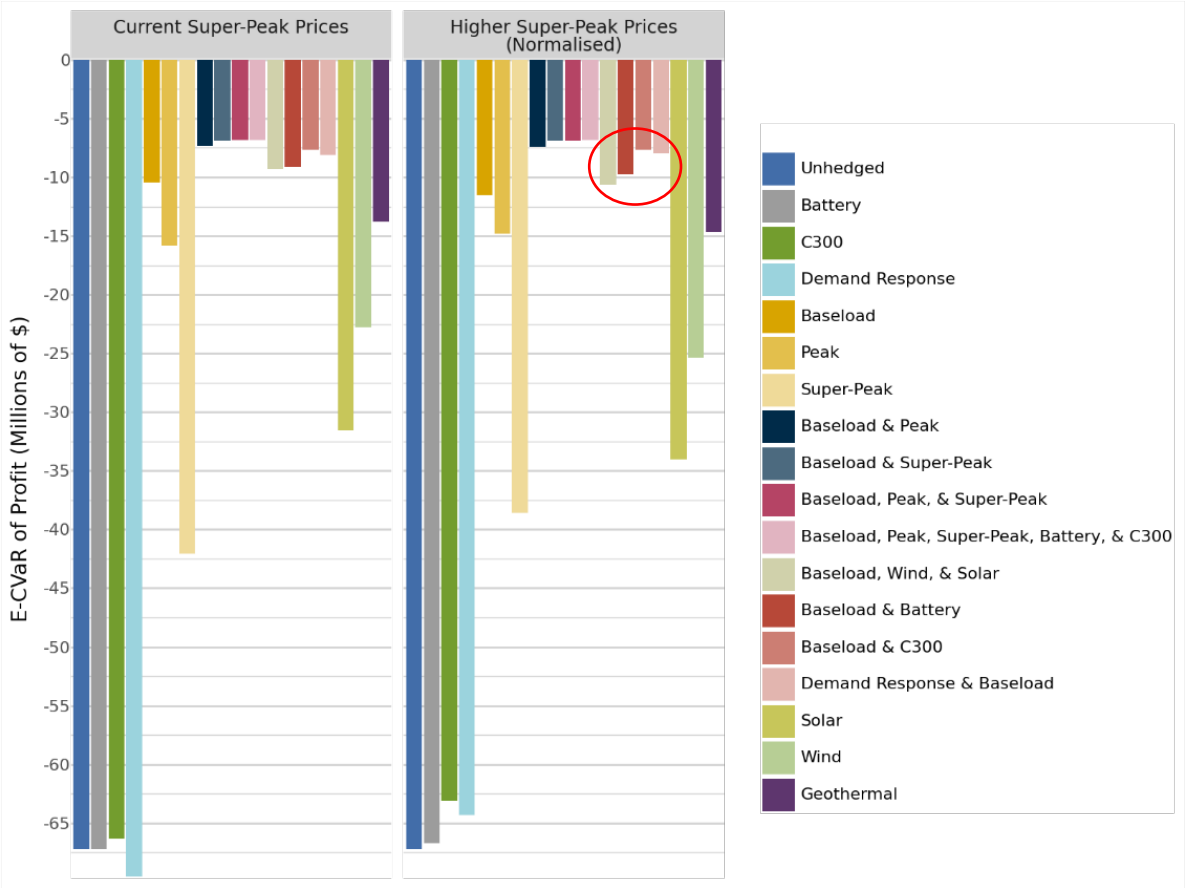


Higher prices at super-peak times

5.8. In this scenario, prices in super-peak (morning and evening peak) periods were increased by 50%, while prices in other periods were reduced by around $20/MWh to maintain approximately the same mean.

5.9. The modelling indicated that, in this scenario, wind and solar PPAs in combination with baseload futures and a BESS in combination with baseload futures were both slightly less effective risk management tools than today, although the latter to a lesser degree. Demand response in combination with baseload futures performed about the same, as did C300 caps in combination with baseload futures (Figure 4). Note that the data in the right-hand panel has been normalised to make it easier to compare the relative impact on different hedging options.

Figure 4: Higher super-peak prices: Sum of E-CVaR in each island, quarter, and day type by portfolio.



5.10. Note that this analysis is from the perspective of hedging a retail load profile of mainly residential customers. It does not necessarily apply to industrial customers or retailers who have a relatively flat load profile and who may be able to shape their load to match a PPA generation profile or to commercial customers whose load profile already closely matches a solar generation profile.

Chapter 7: Is market power impacting on risk management?

Contents

1. Purpose

1.1. In this chapter we consider whether the four large gentailers individually are likely to have *substantial market power* in one or more markets relating to risk management products, as that term is used in section 36 of the Commerce Act 1986. We also consider whether those same parties are working together to exercise market power collectively.

1.2. The existence and/or exercise of substantial market power is not specifically necessary for the Electricity Authority to exercise its power to make policy changes through the Code (see chapter 1[1]). However, it is a core part of the way in which the Commerce Act complaints from non-integrated retailers have been framed, with each strongly asserting that the gentailers have market power and are misusing it, including by refusing to supply certain risk management products and/or via margin/price squeezes. If substantial market power exists in relation to the supply of a risk management product/s, or if coordinated market power is being exercised, there is a significant risk that it will lead to outcomes contrary to the Authority's objective of promoting competition unless mitigated.

1.3. Accordingly, considering whether or not any of the gentailers have substantial market power or are exercising market power collectively, is helpful to our analysis as it assists in:

(a) Better understanding the nature of any problem;

(b) Framing any potential intervention.

1.4. For the avoidance of doubt, we are not seeking to make a definitive finding regarding whether a gentailer has or is exercising substantial market power in any relevant risk management market, or any broader s36 assessment – that fits better with the role of the Commerce Commission. Instead, we draw insights from our own market power analysis as to whether there are any problems that may exist, and which might require policy intervention.

1.5. We note that even if no gentailer has substantial market power in any relevant risk management market and there is no evidence of coordination, there may still be good reasons for a policy intervention in relation to risk management to promote competition in the retail electricity (or indeed wholesale) market.

2. Preliminary findings

2.1. For a gentailer to hold substantial market power in relation to risk management, we consider a number of conditions need to hold true:

(a) Shaped hedge contracts are a necessary aspect of efficient peak time risk management

(b) Having flexible generation and fuel is a pre-requisite to sustainably offering those shaped hedge contracts

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[1] For this same reason, while chapter 4 refers to market power, it deliberately does not seek to engage with the Commerce Act framing of substantial market power.

(c) There are high barriers to building new flexible generation capacity for all participants, including gentailers

(d) Gentailers have the ability and incentive to individually influence the price or supply of hedge contracts,[2] for reasons other than fuel scarcity, despite there being other suppliers and/or substitutes.

2.2. For the purposes of this analysis we accept that the first three of the conditions above can be satisfied at this point in time, noting that in chapter 4 we did not come to a definitive view on the precise boundaries of the relevant market/s.

2.3. While there are substitutes for a portfolio of baseload and super-peak hedges, some of these substitute products (battery renting, demand response – especially with mass market consumers, and retail tariffs) are just starting to be deployed in the New Zealand market, so may be some way from being able to discipline prices for other risk management instruments.

2.4. On balance though, we consider that:

(a) The evidence is mixed in relation to whether the fourth condition is satisfied for unilateral substantial market power;

(b) We have not seen any evidence to suggest that coordinated market power is being exercised.

2.5. While, as noted above, we do not consider that the Authority needs to draw any conclusions on market power, the evidence (refer chapter 5) we have reviewed allows us to make the following relevant findings:

(a) Non-integrated retailers are generally getting responses to their RFPs for shaped hedges, but often not multiple responses so the market is thin, and many responses are non-conforming

(b) Each gentailer seems to approach this market differently, and this is reflected in the different ways they respond to RFPs. This could be due to the RFP/response way of interacting in this market, location factors, etc

(c) Uncertain or scarce fuel supply, and prudent security of supply positions, are used as justifications for risk aversion by some gentailers when responding to RFPs (though we cannot form a definitive conclusion on these being the main drivers of all refusals from the information supplied to us by gentailers)

2.6. The evidence also suggests that the current OTC RFP process is not a particularly effective way of securing a negotiated outcome where gentailers offers converge with non-integrated retailer needs.

2.7. In aggregate, some of the response and price indicators (see chapter 5) suggest that the current process is unlikely to be securing the best competitive outcome in the risk management market (regardless of any specific approach taken to substitutability analysis – see chapter 4).

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[2] Such as raising prices above competitive levels, or withholding supply despite having available capacity.

3. How could substantial market power in relation to risk management arise, and what harms might be occurring?

3.1. Only parties operating in conditions of perfect competition lack any market power. So, in practice, each gentailer, will have some market power at least in certain circumstances and over certain periods. The notion of "substantial market power" (as that term is contemplated in the Commerce Act) effectively establishes a threshold at which it is recognised that a particular person has sufficient market power such that its unilateral conduct has the potential to adversely impact competition by itself.

3.2. The essence of substantial market power is the ability to act without effective constraint: ("to give less and charge more"). A sole supplier of an "essential service" (a monopoly) would generally have substantial market power because there would be no constraint from alternative suppliers, particularly where the conditions mean that new entry is challenging. By contrast, any parties with multiple significant competitors, would ordinarily be constrained by those competitors such that none of them would have substantial market power. Accordingly, the question arises as to whether there are particular features in risk management markets that mean that, notwithstanding the presence of multiple significant competitors, each of the gentailers is able to operate without effective constraint.

3.3. Otherwise, there is a question of whether the gentailers effectively remove those constraints on each other by acting in a coordinated fashion (ie, colluding). In that scenario, they would be exercising "coordinated market power", even though no one single party would have substantial market power.

3.4. Earlier in this paper we explain why retailers need access to risk management. This review particularly focused on risk management of intraday shape. Gentailers are currently the primary supplier of this type of risk management option: hedge contracts that are not ASX baseload. In the OTC market, risk of intraday shape is managed with shaped forward contracts. For this primary supplier role to translate into gentailers having substantial market power in any relevant risk management market, we consider that the following would have to hold:

(a) *Condition 1:* Shaped hedge contracts are a necessary aspect of efficient peak time risk management (for at least some non-integrated retailers or other parties that need to manage the same risk, such as large industrials)

(b) *Condition 2:* Having flexible generation and fuel would be a pre-requisite for sustainably offering significant volumes of those hedge contracts – gentailers currently own the vast majority of flexible generation in New Zealand[3]

(c) *Condition 3:* It would have to be very difficult to build further flexible generation at scale

(d) *Condition 4:* The gentailers would have the ability and incentive to individually influence the hedge contract market (through increased prices or withholding

[3] Nova, Pioneer and Manawa Energy also own substantial flexible generation. Both Nova and Pioneer are vertically integrated, and Manawa Energy has entered into an agreement with Contact Energy for Contact to take over its business subject to clearance by the Commerce Commission.

supply) despite there being multiple other gentailer suppliers, or be able to effectively co-ordinate their activity so that in aggregate they do the same.

3.5. For the purposes of this analysis, we assume Conditions 2 and 3 above are satisfied based on the following:

Hedges need to be backed by flexible generation

(a) Financial hedges can be offered without flexible generation backing: brokers and the commercial market maker do so. In practice though, it is only parties with flexible generation that offer a substantial volume of shaped OTC contacts. Without this flexible generation backing any party selling shaped hedges would need to have a large appetite for financial risk as unlike developed insurance markets, there is no obvious way to de-risk a position.

Building new flexible generation at scale is difficult[4]

3.6. There are a range of reasons why it is difficult to build new flexible generation:

(a) Doing so is very capital intensive

(b) New large scale hydro generation likely faces significant consenting issues, a very long development process, and is high cost to build. The most cost-effective hydro generation sites are likely to be those that have already been developed, and are now owned by the gentailers. It is therefore highly unlikely that the large scale hydro developments built from the 1960s to the 1990s could be replicated today at an efficient cost.

(c) Peaking thermal generation is likely easier to build than hydro, but faces high carbon costs and uncertain fuel supply, as well as a long-term policy environment where New Zealand is seeking to transition to a low emissions economy, ie, away from thermal fuel.

3.7. Building new flexible generation remains possible – for example Nova completed building its Junction Road gas peakers in 2020. It is also possible that new fuel sources could expand the feasible flexible generation options, eg, Genesis has trialled using biomass as fuel at its Huntly plant, rather than gas or coal. But at this point, substantial new flexible generation seems unlikely to enter the system, at least in the period relevant to the near term supply of risk management options (noting also the substantial lead times for these investments).

3.8. We consider Conditions 1 and 4 further below.

3.9. We note that, if any of the gentailers does have substantial market power in relation to the supply of a risk management product/s, we would be concerned not only about the potential impact on that market, but also about how that gentailer's incentives might affect competition in other markets because of their vertical integration. A gentailer with market power in relation to risk management would have an incentive to resist helping its competitors in the retail or wholesale markets, ie, to limit (beyond any scarcity driven limits) or overprice the supply of risk management products to

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4 As demonstrated by the small volume of flexible generation that is committed, being actively pursued, or being considered in the current investment pipeline – see Investment pipeline | Tableau Public.

competitors to give the gentailer's own retail or generation functions a competitive advantage.

3.10. To be clear, we do not consider that vertical integration is problematic or anti-competitive per se. It can be an efficient and effective financial risk management approach in a sector such as electricity, as demonstrated by other participants (outside of the four large gentailers) being integrated – Nova, and recently Pulse/Pioneer. But vertical integration presents particular risks when substantial market power is present in upstream markets due to the incentive to leverage that substantial market power into downstream markets that are otherwise competitive.

4. Are shaped hedge contracts a necessary aspect of peak time risk management (condition 1)?

4.1. Chapter 4 sets out our analysis of other risk management options as potential substitutes for shaped hedge contracts. That analysis helps us to better understand the scope of the market in which we are assessing whether any of the gentailers have market power.

4.2. This modelling shows that no single strategy works for all market states (as parties are always trading off profit in one market state to reduce losses in another). These are a set of combinations that perform quite well in most scenarios, but these are not immune to being outperformed in others. These are:

(a) baseload + peak
(b) baseload + super-peak
(c) baseload + peak + super-peak
(d) baseload + peak + super-peak + battery + C300
(e) baseload + wind + solar
(f) baseload + battery
(g) baseload + demand response
(h) baseload + C300

4.3. Our modelling, combined with evidence we have received to date that these options are widely used for risk management by non-integrated retailers or are being considered for use in the future, suggests that there are alternatives that perform as well as a portfolio of baseload hedges and super-peak hedges.

4.4. However, the products associated with each of the options above that rely on something other than hedging (battery renting, demand response, and retail tariffs) are currently only starting to be deployed in the New Zealand market. We note particularly that:

(a) While significant industrial demand response has been or is being contracted, mass market demand response is still nascent (as the flexibility market and consumer willingness develops), albeit growing quickly and attracting significant interest from retailers.

(b) It is likely that BESS (battery energy storage systems) will play a greater role as the marginal provider of flexibility over time as they are rolled out over the next decade.

(c) About 63% of the plans listed on Powerswitch[5] reward consumers for shifting load in some way. While this dataset does not contain all offered plans, and this is not a measure of the plans that consumers are on now, it is indicative of the direction the retail market is going.

4.5. Because some of these substitute products are only just starting to be deployed in the New Zealand market, they may not yet be able to discipline the prices of shaped OTC hedge contracts (even if they will or may provide this competitive constraint in future).

4.6. So for the purposes of exploring this market power question, and consistent with our understanding of Commerce Commission practice to most clearly isolate and assess potential competition concerns, we have used a narrower (ie, conservative) potential market (baseload and shaped hedge contracts only – refer chapter 4) when considering condition 1, which means it is plausible that this condition could be satisfied, and when assessing indicators of substantial market power (condition 4).

4.7. For completeness, we also make the observation that, of the non-integrated retailers with customer bases above 1,000 ICPs (as at 30 October 2023), only some have been seeking OTC super-peak hedges to manage risk (over the period we have information for). This may reflect a combination of factors, including that different non-integrated retailer business models are more suited to different risk management options (eg, Pulse has now vertically integrated), and that super-peak hedging prices have been trending up (see chapter 5). But it is also consistent with our conclusion in Chapter 4 that non-integrated retailers are able to plausibly use different risk management options to manage the risks that these non-integrated retailers manage via super-peak hedges.

5. Indicators of substantial market power – gentailers influencing hedge contract prices and availability (condition 4)

5.1. In assessing whether or not gentailers could have substantial market power, we considered market conduct and trends. While none of the observations below are conclusive, they provided a useful range of indicators of the extent to which market power might be present.

Unilateral substantial market power

5.2. If any of the gentailers have unilateral substantial market power, they would be able to act independently of competitors or customers to profitably and sustainably raise prices or restrict output in relation to the supply of a risk management product/s.

5.3. The following indicators suggest that one or more of the gentailers may have unilateral substantial market power:

(a) *The price of super-peak hedges may not be consistent with competitive prices and has slightly increased over the measurement period – refer chapter 5.* This could be indicative of a unilateral ability to increase price without a competitive

[5] As at September 2024.

response, ie market power. However, this increase in price could also indicate fuel scarcity or other uncertainty about the ability to cover a contract, ie factors not necessarily linked with gentailers' degree of market power.

(b) *Gentailers electing not to respond to some super-peak RFPs, or providing non-confirming responses – refer chapter 5.* This could be due to location factors, our nodal market, geographically concentrated generators, or the inability to get the necessary financial transmission rights within the RFP timeline. This could also be due to physical withholding of flexible generation from the OTC market that you would not expect to see in a workably competitive market, although we note that one gentailer did price the vast majority of RFPs (99% of RFPs for peak and super-peak cover received at least one offer). While we acknowledge that the ability to supply depends on fuel conditions, we cannot form a definitive conclusion on this being the main drivers of all refusals or non-conformance from gentailer documentation. [6]

5.4. The following indicators suggest the opposite, ie, that one or more of the gentailers may not have unilateral substantial market power:

(a) *There are four gentailers (as well as Manawa Energy and others) each with a sizable amount of flexible generation.* Because of fuel and plant issues, no one gentailer can consistently hold a level of market share that confers substantial market power, ie, it doesn't appear to any gentailer alone has sufficient control over an essential input for retailers' businesses that would amount to unilateral substantial market power.

(b) *One gentailer (Mercury) priced responses for the vast majority of RFPs.* This was a different approach to the other gentailers, and is inconsistent (for Mercury at least) with the refusal to deal construct put forward by the non-integrated retailers in support of their unilateral substantial market power view. The different approaches of gentailers is more consistent with the different fuel and plant configurations of each (eg, Genesis currently owns very little truly flexible generation as Huntly requires substantial time to start).

(c) *Gentailers investing in further flexibility*: gentailers are investing in demand response, batteries, upgrading their hydro generation capacity and flexibility, and thermal generation flexibility. This expansion of the supply of risk management options is inconsistent with gentailers having and exercising unilateral substantial

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[6] Evidence includes:

- In some cases, Meridian chose not to respond [to RFPs] from gentailers or speculators "because there was limited commercial interest in the proposal, ie, the contract did not suit our portfolio at the time". Meridian said that it always endeavors to respond to at least some aspect of each request from non-integrated retailers.
- Some gentailers unilaterally decide that they would be unlikely to offer a competitive price, and therefore did not price the RFP/test the market
- One gentailer was less willing to engage with some legitimate counterparties (brokers) as hedge market customers, describing them internally as "speculators" and "these turkeys".

We have considered whether to seek further clarification from gentailers of the basis for any refusals to price responses to RFPs for shaped hedges, but decided that this was unlikely to lead to a more definitive view than the contemporaneous documents. As set out in chapter 8, we consider that this uncertainty is better addressed going forward by clearer requirements for gentailers around offering shaped hedges.

market power, as it likely reduces peak spot prices, and the value of their existing flexible generation.

(d) *Gentailers offering new risk management products to the market:* Genesis Energy's Huntly firming options (HFOs); Contact Energy seeking expression of interest in relation to services from its Stratford battery. These offers, while different to an exchange based or bilaterally traded hedge, are the opposite of physical withholding. This is relevant if it expands total supply, so would be less likely to be undertaken by a party with existing market power – introduces a new firming asset (Stratford battery), or means flexible generation runs more (HFOs).

(e) We also note that we do not more generally observe unused fuel or capacity in the spot market, nor do we observe gentailer appetite to have uncontracted load.

Coordinated market power

5.5. Coordinated market power can be said to be being exercised when some or all of the gentailers act in a coordinated way in relation to the supply of risk management products to raise prices/restrict supply, which in aggregate effectively restricts non-integrated retailers from growing their market shares in the retail market.

5.6. Successful coordination would require two or more of the gentailers to reach at least an implicit understanding between themselves as to their conduct in relation to offering and pricing OTC hedge contracts to the non-integrated retailers.[7]

5.7. We have not seen direct evidence of the exercise of coordinated market power, cf, say petrol stations following the retail fuel prices of their rivals up and down as they are openly posted on boards.

5.8. But we accept that there is nonetheless a general alignment of incentives between the gentailers to:

(a) Primarily supply their own retail functions

(b) Exchange any shortfall or surplus generation with each other or non-integrated retailers

(c) Otherwise not assist their downstream non-integrated competitors by offering further hedge contracts.

5.9. By contrast though, OTC responses in practice demonstrate little indication of gentailers collectively seeking to manage the market:

(a) Substantially different approaches are taken by different gentailers as to whether to respond to RFPs from non-integrated retailers[8]

(b) As the data received from non-integrated retailers demonstrates, there is often a material dispersion of prices offered by different gentailers for shaped hedges.

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7 There has been no allegation of actual collusion by the gentailers (ie, in breach of ss27 or 30 of the Commerce Act). While it was not a core focus of our work, we have not seen any indicators of this in the evidence provided to us.

8 Mercury states that it will "endeavour to price all requests from credible sources", and appears to do so. Meridian on the other hand may choose not to respond to some aspects of a request if "the contract did not suit our portfolio at the time".

Another relevant factor – gentailers matching their generation and retail portfolios

5.10. While it is not in our view an indicator of substantial market power, we observe that gentailers each broadly "match" their generation and retail books, ie, contract with customers to a similar level[9] to their own intermittent and flexible generation capacity.

5.11. This matching is economically rational, but in practice it means that gentailers tend to only trade risk cover (buying or selling contracts) at the margins,[10] to keep their books in balance. They will have strong incentives to sell surplus generation as their fuel position settles. This may also partly explain the low numbers of responses to some RFPs. But beyond that point gentailers may have less of a consistent incentive or ability to sell more hedge contracts (or compete for extra mass market customers). Accordingly, this matching may have an impact on competition.

Preliminary findings on market power

5.12. Based on the evidence we have seen, we make the following observations:

(a) We have seen no evidence of the exercise of coordinated market power.

(b) The evidence is mixed in relation to unilateral substantial market power. It does show that some gentailers are making choices not to price RFP responses. We accept that there could be a range of reasons for this, including location factors, uncertain fuel supply, and prudent/conservative portfolio management. But what appears to be a sensible justification from one perspective (scarcity could be the driver of the indicators noted in 5.3), could be a convenient excuse from another.[11] The evidence we have seen to date does not clearly prove either perspective, so we consider it is important to contemplate both perspectives in any policy response.

(c) Non-integrated retailers are for the most part getting responses to their RFP requests for super-peak contracts, but that relies somewhat on the approach of one gentailer. While the RFP process means gentailers are blind to the other responses provided, non-integrated retailers are nonetheless often not getting the benefit of price competition between suppliers (for super-peak contracts), and are not reassured that they are getting a competitive price.

(d) The propose/respond format of RFPs may not be helping to get the best market outcome. It seems to have resulted largely in a yes/no system of responses. Especially if the gentailers are unable to trade, or do not see substantial upside in competing vigorously to supply these shaped OTC contracts, the format is

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9 Noting any contracted demand response

10 There are exceptions, eg, swaptions for dry years; Genesis seeking long-term contracts for slow start generation at Huntly, ie, to allow it to run Huntly more.

11 We have little doubt that scarcity and uncertainty are legitimate concerns for gentailers, especially where there are fuel availability issues (as has been the case this year). This likely drives gentailers to err towards being risk averse when considering whether to offer marginal flexible generation in response to an RFP - retaining that fuel may be more attractive in uncertain times than the marginal extra profit (and extra risk) from suppling a hedge contract.

The more difficult question is whether scarcity and uncertainty is the main driver of gentailer choices to not offer contracts in response to RFPs in each case.

likely not conducive to achieving a negotiated outcome where gentailers offers converge with non-integrated retailer needs.

5.13. We are conscious that the Commerce Commission has previously (in 2009) made findings in relation to the market power of the generators. However, we have been reluctant simply to "lift" these findings for the purposes of this review. First, they concerned the spot market. Further, the Commission's findings are now 15 years old and the Authority has improved regulation and monitoring of trading conduct in the spot market since that time.[12]

5.14. The Commission's findings were based substantially on the Wolak report[13], which was in turn based on an extensive data analysis exercise aimed at assessing whether "rents" were being earned from consumers. The results and methods of this report have been widely criticised.[14] In 2021 the Authority undertook a structure, conduct, performance review of the spot market. The results can be found at https://www.ea.govt.nz/projects/all/review-of-wholesale-market-competition/.

5.15. In any event, the Commission's 2009 findings were confined to certain generators having the ability to exercise market power *under certain system conditions* [emphasis added][15]. It is at least arguable that market power of this nature (if accepted to remain today) may not translate easily into the risk management context where many requests for supply would be expected to occur outside the period in which the relevant conditions allowing for the extraction of rents are prevailing. Accordingly, in this review we have sought to draw inferences from our own market power analysis as it relates specifically to risk management.

6. Is gentailer internal transfer pricing a related indicator of market power?

6.1. Finally, one other market power related point has been made by non-integrated retailers that we have considered in this review.

6.2. In addition to their concerns about the availability and pricing of hedge contracts, non-integrated retailers have also raised concerns about gentailer internal transfer prices (ITPs) – the price in gentailer financial accounts at which electricity is "sold" from their wholesale function to their retail function. non-integrated retailers effectively say that the gentailers are making large wholesale margins, and then subsidising their retail

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12 Evaluations of these provisions demonstrate the observed improvements to trading conduct: https://www.ea.govt.nz/documents/2157/Information-paper-Post-implementation-review-of-the-trading-conduct-provisions.pdf.

13 Frank A Wolak, *An assessment of the performance of the New Zealand wholesale electricity market,* 19 May 2009: https://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/new_zealand_report_redacted.pdf

14 For example https://www.nzae.org.nz/wp-content/uploads/2011/08/Jackson_and_Hogan__Critique_of_Wolaks_Evaluation_of_the_NZ_Electricity_Market.pdf.

15 Para vii, Commerce Commission, Electricity investigation report, 22 May 2009: https://comcom.govt.nz/__data/assets/pdf_file/0025/219094/Electricity-investigation-Investigation-report-21-May-2009.PDF

functions through low ITPs. This is an aspect of the margin squeeze complaint made by non-integrated retailers. Non-integrated retailers also claim that gentailers are running their retail functions at a loss, again using ITPs as the relevant input price.

6.3. If gentailers' ITPs are having a competition impact, this may be an indicator of market power. That is, gentailers would need to have some level of upstream market power if they were able to use a combination of ITPs and their offers of hedge contracts to other retailers to effectively skew competition in the retail market in favour of their own retail functions.

6.4. We do not consider though that ITPs are having this impact. This is because gentailers ITPs are intended to be used for internal accounting only and are not a significant driver of any external pricing (retail or hedge contract). Different gentailers disclose their use of the ITPs differently:

(a) Meridian: "The ITP is not used as an explicit pricing input when we set retail tariffs"

(b) Mercury: agreed that their ITP has "limited application in commercial decision making"

(c) Contact: "Retail prices cannot be directly derived from the ITP".[16]

6.5. These disclosures were expanded on in interviews conducted as part of the Authority's post-implementation review of the ITP and retail gross margin disclosure regime, released at the same time as this risk management review, which recorded that:

> **"**Gentailers said that ITPs are used as one input – alongside other inputs - for decision-making purposes and to inform mass-market prices. They said they are used as an indicator to assess general trends in the cost of energy but are not used as the definitive cost of energy.
>
> To determine retail prices, gentailers said they also analyse and assess market conditions, geographical conditions, consumption profiles, competitor behaviour, market share, customer churn, regulatory conditions, and the balance of their overall portfolio among other related factors. Gentailers said that ITPs are not used as a price point to sell to third parties.**"**

6.6. While they have used ITPs in their indicative margin squeeze calculations, we understand that non-integrated retailers also take the view that "the ITP disclosure requirements are meaningless, with the gentailers stating that the ITP is not used to set their retail pricing and is an artificial construct", ie, what the currently disclosed ITPs do and do not impact appears not to be a contentious point.[17]

6.7. On the basis that gentailers have confirmed that the ITPs in themselves are not a significant driver of their external pricing or commercial decision making (ie, where they could impact competition), we do not consider that the ITPs are causing a specific competitive harm, or that their existence is an indicator of market power.

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16 Refer FY 2022 ITP disclosures at Electricity Authority - EMI (market statistics and tools) (ea.govt.nz).

17 See Matthews Law's letter, on behalf of four non-integrated retailers, the Electricity Authority Chair and Chief Executive dated 7 August 2024 at paragraph 69d.

6.8. In an environment though where non-integrated retailers are concerned about the competitiveness of the pricing of hedge contracts offered to them, we reiterate the post-implementation review conclusion that “it seems clear that some change should be made, ie, that disclosing ITPs in their current form is a regulatory requirement of limited, if any, benefit.”

6.9. As discussed in the post-implementation review, the Authority intends to reconsider the role of ITPs and the ITP/RGM disclosure regime after submissions have been received to this review. We would welcome further feedback on possible measures for assessing competition, in light of the evidence presented in this review and the post-implementation review.

Chapter 8: Preliminary conclusions from investigation phase

Contents

1. Purpose

1.1. This chapter sets out and seeks feedback on the preliminary findings from the investigation phase of the review based on the evidence gathered.[1] It also sets out a list of preliminary criteria for appropriate potential intervention.

2. There are diverse risk management options being deployed in the market

2.1. Chapter 4 sets out the range of risk management options being deployed in the market by non-integrated retailers now. All of the non-integrated retailers that we looked at use a portfolio of products for risk management, and all use a different mix in their portfolios.

2.2. In addition, the supply side of the risk management market is evolving quickly. The response to Contact's Expression of Interest for battery risk management products has included interest from non-integrated retailers, for both virtual battery services and for super-peak caps. The Genesis HFO was fully subscribed.

2.3. Chapter 4 also sets out the PPAs that have been entered into in the last two years. It suggests that retailers and load customers are becoming increasingly quasi-vertically integrated.

3. The OTC market seems to be working in most cases, but is not deep or liquid, and is subject to some uncertainty

3.1. Chapter 5 analyses the data we collected on responses to RFPs and the resulting trades.

(a) Almost all requests (over 99%) received at least one offer, and most baseload, peak and super-peak requests received at least one conforming offer.

(b) Non-conforming responses create the opportunity for a negotiated outcome where gentailers' offers converge with non-integrated retailer needs, and likely reflect the complexity on both sides of the market. But the current RFP process is unlikely to be best suited to resolving the range of supply factors including fuel, and what is required on the demand side.

(c) Shorter duration requests are more common.

(d) Prices for peak and baseload hedges are consistent with ASX prices and a high proportion of trades were from conforming offers. This suggests baseload access is not inhibited by the difficulty and cost of trading on the ASX.

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[1] As set out in the programme initiation document: https://www.ea.govt.nz/documents/4594/Risk_Management_Review_PID_final.pdf

(e) We cannot definitively conclude that super-peak prices are competitive as we haven't been able to include premia that we know exist, but can't quantify, such as liquidity premiums.

(f) Energy scarcity in 2024 contributed to more non-conforming offers being traded, falling response rates, fewer trades and shorter duration baseload RFPs increased.

4. Modelling suggests that a portfolio approach to risk management is more likely to be profitable and reduce risk

4.1. We modelled 17 risk management instruments and combinations of instruments over 40 market states (as parties are always trading off expected profit in one market state to reduce expected losses in another). This modelling measured the risk reduction and profit that the instruments/combinations yielded. It takes both volume matching and volume optimisation approaches. (See methodology in Appendix B.)

4.2. The modelling shows that no single strategy works best for all market states. There is a set of combinations that performs quite well in most market states, but these are not immune to being outperformed in others. These are:

(a) baseload+peak

(b) baseload+super-peak

(c) baseload+peak+super-peak

(d) baseload+peak+super-peak+battery+caps

(e) baseload+wind+solar

(f) baseload+battery

(g) baseload + demand response

(h) baseload + caps.

4.3. These modelling results are set out in figures 8, 9, 17 and 18 of Appendix B. The performance of these combinations is robust to the inclusion of risk premiums (figures 22 and 23) and the other sensitivities examined in section 10 of Appendix B. This includes scenarios that are designed to mimic what the future power system might look like.

4.4. These results show the importance of baseload hedge contracts to any successful risk management strategy, but also that this is unlikely to be sufficient on its own. The addition of some way to manage peaks is necessary, and there are a range of ways to achieve this.

4.5. These modelling results are consistent with the range of risk management approaches that we see in the market now.

5. The evidence implies criteria for intervention

5.1. The evidence suggests that a deeper and more liquid OTC market would benefit consumers particularly for those hedges that can be combined with baseload hedges to create effective portfolios (ie, peak, super-peak and caps). A deeper OTC market would also provide reassurance against the risk that gentailers are withholding for any reason that is not related to ability to supply.

5.2. In this section, we discuss key criteria that might be required for any policy intervention in the risk management space, flowing from the evidence and analysis in this review.

5.3. The large number of non-conforming offers that are traded suggests that there is scope for sellers and buyers to negotiate. This suggests what is being traded is complex. The existing RFP process is, however, not a good institutional arrangement for dealing with complexity because of the limited scope for negotiation and an unlimited scope for requests. Trading arrangements should also be adaptable to the firming required for an increasingly renewable power system. This suggests a criterion:

Cut through the complexity of the market on both the supply and demand side

5.4. The plurality of risk management approaches we observe, and those that our modelling suggests are effective, means that innovation is, and will continue to be, important for risk management. Innovators that are able to bring risk management options to those wanting them will help improve competition and thereby benefit consumers. The market should expect this innovation from retailers – it is a core part of their role – and reward it. This will support a portfolio approach to risk management, and reduce the reliance on existing flexible generation which will become increasingly scarce. This suggests a criterion:

Ensure incentives for participating in all types of risk management are maintained – demand response, syndicated batteries, Huntly firming options etc

5.5. If innovators and investors are going to invest in bringing risk management products – generation, demand response, batteries etc – to market, there has to be a reward to do so. This suggests a criterion:

Ensure incentives for investing to supply risk management options are maintained

5.6. Generation, demand response and batteries in particular can back risk management offers, but are also able to get revenue from a variety of sources. That ability to get revenue from other sources is what makes/keeps these risk management options cost competitive, better ensuring efficient input costs for retailers. This suggests a criterion:

Ensure risk management options that have alternative uses – demand response, batteries – have access to other markets to help make them economic for risk management

5.7. While generation is not required to write a hedge, generators are in practice the main underwriters of OTC contracts. Winter 2024 provides a stark reminder that all generation is intermittent in the sense that while capacity is always available, it

takes energy to underwrite a contract. In the absence of large-scale, well-financed speculators the ability to generate must impact the supply of contracts. This suggests a criterion:

Consider ability to supply, which in turn relates to fuel supply conditions

5.8. In our analysis of data on super-peak pricing we were unable to estimate some of the premia that we know apply. We note that trades continue to be made even at high mark-ups over the ASX prices. However, we are unable to form a preliminary conclusion whether or not the prices are competitive. This suggests a criterion:

Ensure transparency for pricing methods, and be able to validate pricing outcomes

5.9. The central importance of risk management to the retail market has been highlighted by the OTC working group, MDAG and the Energy Competition Task Force. This paper also highlights the complexity of risk management and the potential for innovation. It therefore warrants some attention in terms of monitoring outcomes and trading activity. In addition, increased transparency regarding the pricing of shaped OTCs would be valuable data for all participants, but particularly those seeking to invest further in other risk management options (eg, to better assess the value of investing in a battery). This suggests a criterion:

Ensure transparency around market prices and quantities is ongoing and timely

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Glossary of abbreviations and terms

Glossary	
ASX	Australian Securities Exchange. See “exchange traded”.
Baseload	A fixed volume of energy is traded during a fixed period for a fixed price, for all trading periods (same volume in each trading period). Existing ASX baseload contracts do not have separate products for business days and non-business days, but OTC baseload contracts can be for either business days only, or for all days.
BESS	Battery energy storage systems.
Buyer (or Owner)	The buyer (or owner) is the entity that purchases the electricity either from the spot market or via contracts/futures.
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
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. See “VaR”.
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.
DNG	Dispatch notification generation. See also DNL. The dispatch notification product went live in April 2023. It provides a low-cost path for owners or aggregators of small-scale generation and flexible load to directly participate in the wholesale electricity spot market.
DNL	Dispatch notification load. See also DNG.
EOI	Expression of interest - to gauge the interest in engaging in a transaction before issuing a more detailed Request for Proposal (RFP).
EPR	Electricity Price Review (MBIE 2019). https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-consultations-and-reviews/electricity-price-2018-19
ESA	Electricity supply agreement.
Exchange traded	Standardised contracts (futures) traded via an independent third party, such as the ASX. They all have standardised terms (monthly or quarterly), profiles (baseload) and nodes (OTA or BEN). There is no ISDA required to trade and no credit risk for either party. Exchange traded futures require access to a clearer and daily margining, both of which can prohibit participation.
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.
Forward	A contract to deliver goods at some future date at some fixed price
FPPS	Fixed-price physical supply contract. Under the Code this means a contract that provides for the physical supply of electricity.

	These include FPVVs (fixed price variable volume) and FPFV (fixed price fixed volume) products.
FPVV	Fixed price variable volume. See “FPPS”.
FTR	Financial transmission rights. The market for FTRs was created in 2013. Financial transmission rights are designed to assist market participants to manage their locational price risk (LPR) and benefit consumers by enabling greater competition in the wholesale and retail electricity markets.
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.
Hedge	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 hedge contracts, based on contracts for differences (CfDs). Generators and traders can enter financial hedge contracts with other participants to manage the risk of future price movements in the spot market. https://www.ea.govt.nz/industry/wholesale/hedge-market/
HFO	Huntly Firming Options – financial derivatives offered by Genesis Energy. The HFO is designed so that generation capacity (backed by a pre-committed fuel supply) may be notionally called upon during periods of both capacity (winter peak related) and energy (dry year and disruption related) scarcity over the next two calendar years Genesis Energy confirms 85 MW of Huntly Firming Options | Genesis NZ
HSA	Hedge settlement agreement. https://www.ea.govt.nz/documents/9/Lodging_a_hedge_settlement_agreement_with_the_clearing_manager.pdf
ICP	Installation control point number. A unique 15 digit number that identifies a connection to the electricity network.

Initial margin	In the context of buying and selling futures in the electricity market, this is the minimum amount of collateral that must be deposited to ASX Clear (Futures) before entering a futures contract. This margin serves as a security to cover potential losses in case the market moves unfavourably. Initial margins in the ASX are set to cover 99.7% of expected daily price movements (where historical movements in daily futures settlement prices are used as a proxy for expected daily price movements). If the market moves against their position and their account balance falls below the maintenance margin, they would receive a margin call to deposit more funds, ensuring that they can meet their financial obligations. On the other hand, if the market moves in their favour, their account is credited.
ISDA	International Swaps and Derivatives Association (ISDA) - An ISDA master agreement is a standardized document regularly used in over-the-counter (OTC) derivatives transactions, as OTC derivatives are traded between two parties, not through an exchange or intermediary.
ITP	Internal transfer price of a gentailer. 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).
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
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.
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.
MFK	Multiple Frequency Keeping.
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. There is credit risk for both parties unless the deal is lodged with NZX under an HSA.
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. There are three types of PPAs: virtual, physical and private wire. The Authority considers virtual PPAs to be a type of CfD. It is a financial contract in which the corporate offtaker and renewable energy generator agree a defined strike price for electricity generated by the generator's renewable energy project. The parties exchange the difference in the value of spot price and the strike price during the settlement period. The Authority considers physical and private wire PPAs as subsets of fixed price physical supply contracts. A physical PPA is a long-term contract between an offtaker and generator to take a specified amount of electricity at a fixed price per MWh. It is considered a private wire PPA when the transfer of electricity is directly from the generator's facility to the corporate offtaker, rather than through the national grid.
Premium	Fixed amount paid for the rights to buy or sell a contract.
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.
RGM	Retail Gross Margin. 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.
Risk management	The strategies of forecasting and evaluation of financial risks together with the identification of procedures to avoid or minimize their impact.
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.
Settlement	To take or make delivery at maturity. Physical commodity futures usually require commodity settlement, financial futures usually require cash settlement.

Shaped products/contracts	A customized 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.
Sleeved PPA	A corporate PPA is a PPA between a business and a generator. Corporate PPA sleeving describes when a corporate PPA is bundled ('sleeved') into a business's regular electricity supply.[1] In a sleeving arrangement, the business pays for two distinct volumes of electricity: (a) PPA volume at the PPA price, owed to the generator (b) Residual ('firming') volume (total less PPA volume) at the retail tariff, owed to the retailer
Speculation	Buying a derivative that increases your risk with the hope of profiting.
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.
Strike price	A fixed price at which the holder of the option can either buy (call option) or sell (put option) the underlying commodity or financial instrument.
Super-peak	A fixed volume of energy is traded during a fixed period for a fixed price, for trading periods at "super-peak" times – ie, morning and evening peaks (usually the same volume in each trading period that is included).
Swaptions	A financial option that gives the holder the right, but not the obligation, to enter into an electricity swap contract at a future date under pre-agreed terms. Electricity swaps typically involve exchanging a fixed price for a variable (spot) price over a period of time, helping participants hedge against price volatility.
TOU	Time of use retail tariff. Different prices are charged during different time periods.
Variation margin	Daily payments from losers to gainers.

[1] file:///C:/Users/hallj/AppData/Local/Microsoft/Windows/INetCache/Content.Outlook/0WY7GO30/EVA%20renewables%20market%20report%20Q1%20%20Q2%202023.pdf

VaR	Value at risk - a metric used to measure risk, used here to assess risk of one hedging strategy relative to another. It quantifies the extent of possible financial losses from each hedging strategy. For example, if a portfolio has a 20% VaR of $1,000,000 over a quarter, this means there is a 20% chance that the portfolio will lose you more than $1,000,000 over a quarter. See “CVaR”.
VPPs	Virtual Power Plants - networks of decentralized, small-scale power generating units, such as solar panels, wind turbines, and battery storage systems, that are integrated and operated collectively via a centralized control system.