The Authority's response to submissions on the 2021 Market Monitoring Review of Structure, Conduct and Performance in the Wholesale Electricity Market

Executive summary

This paper covers the Authority's response to points made in submissions on the Market Monitoring Review of structure, conduct and performance in the wholesale electricity market – Information paper (WMR). It is not intended as a fulsome summary of submissions and nor have we attempted to respond to all points raised in submissions in relation to the analysis. Rather, we have responded to substantive points raised in submissions where we believe stakeholders would benefit from our response.

This paper does not include the Authority's response to the implications of the WMR's findings. This is covered in the companion paper *Promoting competition in the wholesale electricity market,* which considers the competition implications in the context of the transition to 100% renewable electricity.

While we have adjusted our analysis slightly in light of submissions received, no further analysis or issues raised in submissions has caused us to change our initial observations made in the WMR. We still consider that prices over the review period reflected, at least to some extent, underlying supply and demand conditions, but that there was also some evidence to suggest generators may have exercised sustained market power over the review period. That is, it is ambiguous as to whether the current market is consistently delivering our expectations of competitive outcomes (as set out in the WMR[1]):

- When we tried different measures suggested in submissions to more fully account for gas supply uncertainty, the dummy variable in our regression analysis remained significant and of the same magnitude. That is, we still observe an uplift in prices since the 2018 Pohokura outage that seems to not be fully explained by gas supply uncertainty or other underlying conditions that were controlled for in the regression analysis.
- No points raised in submissions caused us to re-evaluate which indicators to use under the Structure, Conduct, Performance framework (SCP) or our observations in the WMR about each indicator.
- Our traffic light assessment of each indicator – ie, our assessment of each indicator against our expectations of competitive outcomes – remains the same as presented in Table 2 of the WMR for the review period.
- The SCP framework remains our framework of choice for analysing competition issues. There is no conceptual conflict between a short-run marginal cost (SRMC) approach to assessing competition (as used in the SCP framework) and a long-run marginal cost (LRMC) approach. The SCP analysis complements a forward-looking analysis of the investment environment.

[1] Our expectations of competitive outcomes were set out in Table 2 of the WMR, while paragraph 5.7 sets out our definition of market power. https://www.ea.govt.nz/assets/dms-assets/29/Monitoring-Review-of-structure-conduct-and-performance-in-the-wholesale-electricity-market-updated-paper.pdf

The WMR also noted that forward prices were well above the cost of new entry, and for longer than we would expect in a workably competitive market, and that the pipeline of build-ready investment projects appeared thin. Potential reasons mentioned in the review included uncertainty and actions by incumbents to stymie investment. Barriers to entry are a concern to the Authority, as credible threats of entry by new generation provides an important constraint on the exercise of market power and is a key driver of dynamic efficiency.

Because of this concern, and in response to questions raised in submissions, the Authority commissioned a further assessment of the investment pipeline and any factors that may hinder investment. As discussed in the companion paper, the Authority is now more confident about the amount of investment that is committed or actively pursued. There is currently no strong evidence of anti-competitive behaviour that may be hindering investment by independent developers. The high proportion of investment by independent developers suggested by the pipeline is also encouraging for competitive tension on the behaviour of existing generators.

But with ASX contract prices for 2025 still above the cost of entry, there is a case for action to reduce regulatory uncertainty, to streamline consenting processes, and to closely monitor progress on investment and interactions between major generators and independent generators.

Even with most investment projects coming from independent developers and no strong evidence of a lack of competition *for* the market, the structure of the market will remain such that it is dominated by four large generators. These four large generators will also have control of the vast majority of flexible generation. The presence of market power is – and will continue to be – a reality in the New Zealand wholesale electricity market.

Because of this, and in order to ‘promote competition in, reliable supply by, and the efficient operation of, the New Zealand electricity industry for the long-term benefit of consumers’ as required by the Authority’s statutory objective, the Authority proactively monitors trading conduct. This includes referral of suspect cases for investigation by the Authority’s Compliance team. The findings in our Post Implementation Review (PIR) of the new trading conduct provisions suggest the new trading conduct rule and additional monitoring have been effective in leading to offer prices that are more consistent with our expectations of competitive outcomes.

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1 There were various opinions on whether the market is competitive

1.1 The Authority received 31 submissions in response to the *Market Monitoring Review of structure, conduct and performance in the wholesale electricity market – Information paper* (WMR). The Authority appreciates the thoughtful engagement and detailed responses.

1.2 This paper covers the Authority's response to points made in submissions. It is not intended as a fulsome summary of submissions and nor have we attempted to respond to all points raised in submissions in relation to the analysis. Rather, we have responded to substantive points raised in submissions where we believe stakeholders would benefit from our response. Where we have sought to summarise a particular submission, this is necessarily at a high level and may not reflect all the nuances of the submitter's view. The full submissions are available on the Authority's website.

1.3 Submissions were broadly consistent within categories of stakeholder – at a high level, generators generally considered the wholesale market is competitive and supported the status quo, whereas independent retailers and industrial users thought the market is not working and advocated for structural reform.

1.4 Table 1 summarises the opinions from submitters on whether they think the wholesale market is competitive or not. Cells have been colour-coded depending on whether we think the submitter thought the market is generally competitive (green) or not competitive (red) or did not express a conclusive opinion on whether the market is competitive (light orange).

Table 1: Summary of submitters' opinions on wholesale market competition

Submission from	Summary of opinion on wholesale market competition
BEC	The data does not provide any conclusive evidence to suggest there are competitive issues. There may be other factors, including increasing uncertainties and risk, which have contributed to higher prices.
Bryan Leyland	Market settings are wrong and consumers end up paying more for electricity than they should.
Community Energy Network	No direct comments on competition, but support review in order to minimise cost of energy.
Community Power	The current design of the spot market often results in inefficient outcomes, as the most polluting and most expensive generation is dispatched first.
Contact Energy	No evidence of adverse outcomes or systemic issues. Higher prices due to risk premium associated with gas uncertainty.
Electric Kiwi and Haast	"… there are substantial, structural problems in the electricity market, that are harmful to competition, the efficient operation of the electricity market and the long-term interests of consumers...."
Electric Power Optimization Centre	Frequent pre-dispatch auctions may result in sellers extracting as much value as they can. The outcomes of the repeated pre-dispatch discovery

	process can result in productive inefficiencies as generators attempt to meet inter-temporal constraints by altering offer prices. In other wholesale electricity markets intertemporal constraints are handled with two settlement markets- a day ahead and a balancing market.
Energy Link	Gas supply shortages are the underlying cause of high prices, and electricity generators compete with major industrial users for gas. Review of wholesale electricity market cannot be complete unless it also includes a review of wholesale gas market. The market needs more independent generators.
Energy Resources Aotearoa submission	Submission focused on barriers to investment in renewable generation, suggesting that the same uncertainty currently afflicting the gas industry's investment decisions may also be affecting investment in new renewable generation.
Entrust	Ongoing, systemic problems in the wholesale market, high concentration. There is clear evidence that large generators are increasingly abusing their market power.
ERANZ	"...the wholesale market outcomes over the last few years is explainable by well-known supply and demand drivers, leading to the pipeline of new renewable generation projects growing recently."
Exergi Consulting Limited	"…it looks more like traders just experimenting to get better prices, and occasionally getting caught out, rather than the offers to the market working on SRMC's and justifiable water values…"
Flick Electric	"The Authority's analysis has clearly identified "evidence to suggest that prices may not have been determined in a competitive environment"".
Fonterra	"…we observe that the market has suffered several sub-optimal outcomes… For Fonterra, over the last three years our costs for electricity have also materially increased".
Genesis	Did not comment on whether it thought the wholesale market is competitive.
Independent retailers	There are substantial problems with competition in the wholesale market, which has downstream impacts on the retail market.
Mercury	There is little evidence of material competition concerns, instead there is a challenge in maintaining a balanced energy trilemma.
Meridian	Wholesale prices are explained by underlying supply and demand conditions. Higher prices reflect supply and demand conditions. Evidence of the exercise of market power was not found.
MEUG	Some generators often have a large proportion of their offers above the cost of generation and some offers do not reflect underlying conditions. The estimated impact of gas supply uncertainty seems to be very high.
Neil Walbran	Did not comment on the state of competition in the wholesale market. He expressed concern around the observed lack of commitment to new (firmed) renewable generation, and states that it would be "good to see

	the results of the barriers to entry investigation to put some context on the assessment of wholesale competition.”
Nova	No firm evidence of market failure, but there is room for improvement. Not surprised EA unable to conclude if market power has been exercised.
NZAS	No direct comment about competition, but did state that “A system which can support a large scale producer of some of the lowest carbon aluminium in the world while providing over one thousand jobs in its local economy and spending nearly half a billion dollars in the national economy, is, in our view a good system.”
NZ Steel	“The report has identified a number of areas that are not what we believe would be expected in a properly functioning market…”
OceanaGold	“The drivers of wholesale prices remain substantially unexplained and counter-intuitive”.
Octopus Energy	Believe this is a classic oligopoly scenario with observable and persisting competition problems.
Paua to the People	The current wholesale market is severely broken. High-cost thermal generation has been needed and high spot prices have not driven new generation investment.
Paul Maynard	Low price electricity contract with Rio Tinto resulting in higher wholesale market prices.
Roderick Aldridge	The current system is being gamed by the gentailers and NZAS - as evidenced by Aug event, residential power price increases, excess profits found by Stephen Poletti, NZAS subsidy.
Sustainability Trust	Structural changes in the market system are needed if NZ wants a competitive market with a variety of players.
Trustpower	Expect market power to be localised and transitory (if it exists) in the NZ market. Prices explained by number of concurrent events that have compounded in recent years.
Winston Pulp	The market is letting all consumers down, is dysfunctional and needs fixing urgently.

2 Gas uncertainty contributed to the higher-priced offers over the period, but we cannot rule out the exercise of market power

2.1 In the WMR we discussed how the Pohokura outage in 2018 appeared to cause a structural break in electricity prices, as there was a sustained upward shift in prices not explained by gas prices or other underlying conditions, as demonstrated by the significance of the dummy variable in the regression analysis. We discussed how gas spot price volatility and level was indicative of the uncertainty surrounding gas supply. We also discussed how thermal generation had reduced flexibility to firm hydro over the review period, as evidenced by the change in the correlation between hydro generation and thermal generation. However, we concluded that it was not possible to determine if the upward shift in prices was fully explained by gas uncertainty or if there was also an exercise of market power.

2.2 There were a variety of responses in the submissions around our understanding of this step change in prices. Submissions from Contact, Meridian and Mercury argued that it can be fully explained by the uncertainty in gas supply caused by the 2018 Pohokura outage, the decline in Pohokura production from March 2020, and other unplanned gas outages. However, submissions from Hayden Green (Axiom Economics, included as part of Meridian's submission) and Nova argued that competitors could have taken advantage of higher gas prices to raise their offer prices without being displaced by thermal generation. MEUG argued that gas and thermal generation levels returned to normal after three months, so gas supply uncertainty cannot explain the prolonged increase in prices.

2.3 As a result of feedback in submissions, we tried two additional scenarios to more fully account for gas supply uncertainty in our regression analysis (discussed more fully below). When we did this, the dummy variable coefficient was still significant and of a similar magnitude. We therefore still consider that we cannot be certain whether the step change in prices is wholly explained by gas supply uncertainty, or whether the exercise of market power contributed to higher prices over the review period.

2.4 Contact estimates the gas supply risk was responsible for a $44/MWh increase in the spot price. This is based on the increase in the margin between the 50th and 90th EMS price percentile from $0.40/GJ to $6.60/GJ. Contact said that gas uncertainty was evidenced by:

(a) A decrease in gas production, from 190PJ in 2017 to 176PJ in 2020, predominantly due to decreases at Pohokura.

(b) Contact's ability to secure gas contracts in 2019 and 2020 was limited, as shown in Contact's 2019 Annual Results.

(c) EMS gas price volatility increased by 300 percent since September 2018. Average price doubled, but standard deviation quadrupled.

(d) In some months, the upper percentile of gas prices began to converge with the Whirinaki breakeven price.

(e) Gas reserve availability remains cloudy. The estimates of reserves at Pohokura have decreased by 311PJ since 2017 while estimates of reserves at Kapuni, Manghewa and Maui have increased.

2.5 Similarly, Mercury's submission criticised the use of the average cost of gas over the review period. They argued that while only a small volume of gas is from marginal gas contracts, these have a disproportionate impact on the electricity price due to these contracts being likely drivers of marginal offers for electricity supply as supply gets scarcer.

2.6 In the WMR we compared the gas VWAP with prices of gas supply agreements (GSAs). We found that the GSA value weighted average prices are similar to the gas spot price VWAP we used in the regression analysis. We advised that "this gives us confidence that the emsTradepoint VWAP that we have used in our analysis is a good proxy for the cost of fuel for gas generators. We also think that this suggests the emsTradepoint VWAP might be a good indicator of expectations of gas supply risk…".

2.7 To further test the argument of whether the gas spot price VWAP is a good representation of the cost of fuel for gas generators, we replaced the gas spot price VWAP with the 90^{th} percentile of the daily gas prices (volume weighted) in our regression analysis. This was used to represent a more risk averse attitude towards gas prices and addresses some of the concerns highlighted in submissions. We also ran the regression with the addition of the standard deviation of the daily gas emsTradepoint prices, as another indicator of gas supply uncertainty.

2.8 When we made these alterations to the regression, we found that the dummy variable coefficient was still significant and of around the same magnitude.[2] This is consistent with our view above that the gas spot price VWAP is a good proxy for the cost of fuel for gas generators, and might be a good indicator of expectations of gas supply risk. It also reinforces our view that the observed structural break, quantified by the coefficient on the dummy variable, may not fully be explained by gas supply uncertainty alone.

2.9 MEUG's submission pointed out that we did not explain why the \$39/MWh step change which started during the Pohokura outage persisted into 2019 and 2020, despite gas and thermal generation levels returning to normal after three months. If the increase was due to gas uncertainty MEUG expects that gas generation would have been lower compared to earlier periods. They acknowledged that Genesis increased its use of coal and decreased its gas-fired generation compared to 2016-2017, and Contact halved its peaker plant generation after 2018. However, MEUG points out that the average cost of thermal fuel increased by 15.8 percent (estimated to be 43 percent including carbon costs) between 2016 and 2021 but the average price received for electricity increased by 198.5 percent. They also thought uncertainty would increase the proportion of thermal offers priced above SRMC, but Table 9 in the WMR showed mixed changes.

[2] When the 90^{th} percentile of the daily gas prices was included, the dummy variable coefficient increased slightly to \$42/MWh. When we included the standard deviation of the daily gas prices the dummy variable coefficient was very similar at \$39/MWh rounded. Note that our model assumes a linear/constant relationship between the dummy variable and spot prices. We did not test for variation in this relationship over time except for the addition of two further dummy variables as suggested by the structural break analysis (see paragraph 2.16) or interactions of the dummy variable with other variables in the model. See Appendix B for the regression results.

2.10 We discussed in the WMR how we cannot be certain whether the step change in prices persisted due to gas supply uncertainty or the exercise of market power (or something else we may not have accounted for). While the initial Pohokura outage was resolved after three months, there have continued to be ongoing issues with gas supply. One of the reasons gas-fired generation may not have dropped as much as MEUG expected is because observing actual thermal generation after the fact does not indicate the level of uncertainty before the fact. In addition, Methanex, the largest gas user in New Zealand, reduced its gas usage to make more gas available for electricity generation, particularly during the winter of 2020 and 2021 when hydro storage was low. Genesis and Methanex also announced a gas swap for 2022 and 2023, which will see Genesis supply Methanex with gas in the summer and Methanex supply Genesis with gas in the winter. These deals indicate that Genesis was concerned about ongoing gas supply, especially over winter, so sought out alternative arrangements to increase certainty.

2.11 In the WMR, we discussed how uncertainty surrounding gas supply was indicated by gas spot price volatility. Contact also discussed in its submission how the volatility in the gas spot price has increased by 300% since September 2018. We also discussed in the WMR how thermal generation had reduced flexibility to firm hydro over the review period, as evidenced by the change in the correlation between hydro generation and thermal generation. Both pieces of evidence suggest the effect of gas supply uncertainty continued over the review period.

2.12 Hayden Green (Axiom Economics, included as part of Meridian's submission), highlighted how the decline in output from Pohokura tightened supply and reduced flexibility in the gas market, resulting in reduced delivery of contracted amounts. Green argues that this increased the importance of gas storage, increasing the opportunity cost of gas and therefore the short run marginal cost of gas, above any increase in the price of gas. This also increased the opportunity cost for hydro generators, as they had to adjust their assumptions about thermal generators. However, Green's report also highlights how these conditions are likely to encourage the exercise of market power, with generators able to signal 'contrived scarcity' by strategically withholding generation.

2.13 We agree that uncertainty has increased the short run marginal cost of thermal generation and the opportunity cost for hydro generation. We also agree that these conditions could have contributed to the exercise of market power by hydro generators, as discussed in the WMR, including the increase in the Lerner Index using DOASA water values for Mercury and Meridian during the review period (a consistent measure over time of the opportunity cost for hydro generators).

2.14 On the other hand, Meridian discussed its need to manage hydro resources in light of increased uncertainty of gas supply. It argued that, since it does not own gas-powered thermal generation, it did not have as much information about the gas supply situation as generators who contract gas directly from producers. This increased Meridian's uncertainty on how thermal generators would behave in a case of hydro scarcity and may have made it more risk adverse than it would have been with better thermal fuel disclosure.

2.15 We agree that an increase in thermal fuel disclosure would be beneficial for more efficient outcomes in the market. However, we do not agree that this should account wholly for the discrepancy between the percentage of higher priced offers for hydro generators without thermal generation compared to hydro generators with thermal generation, and the increase in higher priced offers over time when compared to costs.

These costs should – at least to some extent – reflect the increased uncertainty surrounding gas supply.[3] As discussed above, the gas spot price VWAP (used in hydro generators' opportunity cost calculations) appears to be a good indicator of expectations of gas supply risk.

2.16 Carl Hansen (Capital Strategic Advisors, included as part of Meridian's submission) pointed out that we should also control for the other structural breaks in our regression analysis that were found in the structural break analysis. We re-ran the regression including a dummy variable from 11 October 2019 and another from 21 October 2020. When these dummy variables were included, we found that all three dummy variables were significant. The original dummy variable (October 2018) coefficient was $42/MWh, the October 2019 dummy variable coefficient was -$21/MWh, and the October 2020 dummy variable coefficient was $40/MWh.[4] This suggests that prices decreased slightly (from the levels post-Pohokura outage) at the end of 2019 for one year before increasing again in late 2020.[5] But the overall observation remains the same: prices increased after the Pohokura outage and remained higher than explained for by the underlying conditions controlled for in the model over the entire review period.

2.17 Nova discussed how offering close to their SRMC risks being dispatched to operate 'on the margin' for an uneconomic period. For this reason, when Nova expects prices to be above SRMC for their fast-start gas turbines they offer the capacity at very low prices (e.g. $0.01/MWh), and when prices are expected to be below SRMC they offer their peakers at a high price that is unlikely to clear to provide security. Other thermal generators also appear to use a similar strategy when offering thermal generation. Therefore, offer prices would not reflect gas SRMC directly, though there is still a relationship between their offer prices and SRMC.

2.18 We consider that increased gas uncertainty and risk aversion caused an increase in spot prices during the review period, but we still cannot rule out that the exercise of market power may have been contributing to these higher prices. Quantifying the premium for gas uncertainty is difficult and depends on the level of risk aversion of each participant. It is therefore still possible that some of the increase was due to the exercise of market power, or some other unidentified source of uncertainty that justified caution in offering.

3 Our focus for this review was – and continues to be – on wholesale market competition

3.1 Some submissions said that we need to widen our focus to include downstream and related markets, and impacts on the environment.

[3] Including both reliability and price risks.

[4] Noting again that we have not tested for any interactions between the dummy variables and other variables in the model.

[5] When these dummy variables were included, the coefficient on the storage variable also decreased slightly, suggesting these dummies could be related to storage. This seems likely for the 2019 dummy variable in particular as it was followed by a high inflow event. See Appendix B for the regression results.

3.2 Entrust and Electric Kiwi said the Authority should consider the climate and environmental implications of the findings and the implications this had on the transition to a market based on 100% renewable electricity. In the companion paper *Promoting competition in the wholesale electricity market* we consider whether wholesale electricity market settings are fit-for-purpose for promoting competition in the transition to 100% renewable electricity.

3.3 BEC said there was limited focus on secondary markets (OTCs, PPAs, futures market) and how they interact with the spot market. Energy Link was also concerned the problem lies in the hedge market, not the spot market. It did acknowledge however that it was important to ensure the spot price was determined in a more-or-less competitive environment, as hedge prices were determined by expected spot prices. The Authority continues to do work to improve the efficiency of the hedge market. This work is discussed in the companion paper. In the later part of this year MBIE will be investigating the use of government electricity purchasing to support investment in new renewable generation, ie, providing assistance for government agencies and local government to explore PPAs. Concept found that overseas investors tend to be more willing to take some offtake risk (especially during the build phase). This suggests that having an offtake agreement may no longer be a pre-requisite for independent developers to proceed with projects. However, access to agreements with other generators for 'firming' or backup supply for intermittent generators appears to be an emerging issue. This is discussed in our companion paper. MDAG is also investigating what contract types are likely to be needed with 100% renewable electricity, and the factors which may impede or facilitate the uptake of these contract types.

3.4 Energy Link argued that a review of the wholesale electricity market is incomplete without including a review of the gas market, which is highly concentrated. While Energy Link acknowledge that it is not the Authority's role to review the gas market, it discusses how the Gas Industry Company's (GIC) review did not look at competition in the gas market. Energy Link argues that "a greater level of scrutiny could and should be applied to the upstream gas market." It gives a number of ideas for inclusion in a regulatory framework for the gas industry (either through the Commerce Commission, GIC with greater powers, or the merger of the Authority and GIC), including limiting the use of market power. As demonstrated through the dry year security of supply event at the beginning of 2021, it is beneficial for the Authority and the electricity industry to have a deeper understanding and greater transparency of any issues in the gas market.[6]

3.5 The retail market was brought up, especially by independent retailers, including Flick, Electric Kiwi and Octopus. Octopus asked why the retail market was not included in the WMR – or at least the interplay between the wholesale and retail markets – as the Authority has responsibility to promote competition in and monitor performance of the electricity industry. Electric Kiwi and Flick both said abuse of market power in the wholesale market was impacting retail competition and so this review should have included impacts on the downstream markets. Similarly, MEUG wanted analysis in how the sustained price increase has impacted different customer groups. BEC noted that wholesale prices impacted large electricity users but these price increases had not flowed through to retail prices for residential and commercial customers.

[6] https://www.ea.govt.nz/assets/dms-assets/30/Final-Electricity-Authority-Dry-Year-Review-2021.pdf

3.6 The Authority agrees that competition in the wholesale market is important for outcomes in the retail market. However, the issues that led to the review concerned competition in the wholesale market, and so the retail market was not in scope for this particular review. The Electricity Price Review (EPR) published in 2019 looked at both the wholesale and retail markets and made several recommendations that either have been or are being implemented. The impact of these changes will be assessed as part of future work programmes.

3.7 NZ Steel said that the recognition of the holistic role of electricity in NZ is absent from the review and that the Authority has a responsibility to take the leading role in these discussions. Consistent with the Authority's statutory objective, the review focused on whether the structure, conduct and performance of the wholesale electricity market were promoting competition in that market for the long-term benefit of consumers.

4 The Authority values competition in the short and long run

4.1 In the WMR, we used the Structure, Conduct, Performance (SCP) framework and looked at indicators under each of these three areas over two and a half years (January 2019 to June 2021).

4.2 Some submissions argued that our analysis was static and too short-term in focus. Meridian argued that competition is a process that occurs over time, and rivalry takes time to organise and have a material effect. It said that we should both extend the analysis past June 2021, and also make some allowance for a period from 1 January 2019. Meridian argued that an analysis of long-term market dynamics would be more meaningful than our static analysis of prices and short-run costs.

4.3 Electric Kiwi and Haast also said the duration of the analysis needs to be extended. Their argument for this was that we should not assume that pre-2019 the market was competitive. Contact said the Authority has undertaken a comparatively short-term analysis of the wholesale market and has not considered the link to long-term market outcomes. Trustpower said that a focus on short-run outcomes is insufficient to form a robust long-term perspective on the quality and nature of an investment environment required for the transition away from fossil fuels.

4.4 The Authority agrees that competition is a dynamic process; this means that we can observe and assess market structures, behaviours and outcomes at a point in time – a short-run or static perspective – but also recognise and promote change over time, in response to price signals and other information from market interactions.[7] The SCP framework explicitly considers incentives for and barriers to entry (and exit) and dynamic efficiency.

4.5 We disagree that two and a half years is too short a time-frame for investigating generator offer behaviour and whether the market is achieving competitive outcomes. Perhaps generators' offering behaviour may have taken some time to adjust to the effects of the Pohokura outage (ie, increased awareness about uncertain gas supply) – ie, to update their opportunity cost expectations to include a risk premium for this uncertainty, but we disagree with Meridian that this process would have taken two and a half years to work through. Generators have an opportunity 48 times per day to change

[7] Electricity Authority, 2011, Interpretation of the Authority's statutory objective

offers in response to conditions and competitor offers. Offers should reflect costs – including these updated expectations – over the timeframe we looked at.

Spot prices give insights into the state of competition

There is no conceptual conflict between SRMC and LRMC approach to assess competition

4.6 Hayden Green (Axiom Economics, included as part of Meridian's submission) argued that the difficulty of measuring SRMC (ie, measuring the opportunity costs associated with managing scarcity) diminishes the usefulness of our analysis. He argued instead that "more insights into the overall state of competition in the NZWM [New Zealand Wholesale Market] can be obtained by asking: are prices above long-run entry costs and, if so, why?". Grant Read (EGR Consulting, included as part of Meridian's submission) also stated that "the real long-term discipline on industry costs, and hence consumer price levels, is not supposed to be spot market competition, but competitive entry." He also stated that prices above SRMC are the norm, rather than the exception, across the vast bulk of businesses and sectors, and is not normally regarded as an abuse of market power. Mercury said that the conventional economic analysis framework for whether material market power issues exist is whether prices are significantly above the long-run cost of entry, and whether there are significant and enduring barriers to entry.

4.7 The Authority agrees that observing where market prices are compared to the cost of entry is a useful test of the extent of competition and (threat of) competitive entry. The WMR raised questions about the divergence between contract prices and the cost of entry.

4.8 However, it does not follow that there is therefore no use in testing whether spot prices are consistent with our expectations of competitive outcomes, even if it can be difficult to measure SRMC. Indeed there is great value in spot prices being competitively determined, so that short run decisions about resource use are efficient. The approaches are complementary.

4.9 As discussed in Annex 3 of MDAG's *High Standard of Trading Conduct Discussion Paper*, the Authority considers "that the correct measure of whether prices are efficient in the electricity spot market is whether average spot prices over time reflect long-run marginal cost (LRMC)."[8] However, as pointed out in that paper, there is no conceptual conflict between an SRMC approach to assessing competition, and an LRMC approach.[9]

4.10 What analysis is appropriate will depend on the circumstances. The SCP framework approach analysing whether prices reflected SRMC over a set time horizon in recent years was appropriate for answering the question of whether the current market settings

[8] https://www.ea.govt.nz/assets/dms-assets/29/09-Fundamentals-of-Efficiency-in-Electricity-Prices-Annex-3-of-MDAGs-discussion-paper-on-the-High-Standard-of-Trading-Conduc-v2.pdf

[9] Grant Read (An Economic Perspective on the New Zealand Electricity Market, 2018, https://www.mbie.govt.nz/dmsdocument/4195-meridian-energy-electricity-price-review-first-report-submission) appears to agree with this, stating "…there is a tension between achieving productive and allocative efficiency in the short run, versus dynamic efficiency in the longer run. Those debates dogged the sector for some decades. Ultimately, though, it was realised that all three views are complementary, not conflicting." And "So far as we know, this theory is not seriously in dispute between the advocates of LRMC and SRMC based approaches to evaluating market performance. At least in principle, all would like to see a pattern of market prices aligning with both, across hydrology years, and time periods within each year."

are resulting in any exercise of market power, or whether competitive outcomes are being realised (provided SRMC incorporates opportunity costs). A longer-term LRMC analysis cannot be used to diagnose the source and extent of problems associated with the withholding of generation or the pricing-up of offers at the margin by generators. The SCP shorter-term analysis[10] complements a longer-term analysis of the investment environment and an assessment of whether prices will tend towards LRMC. The Authority commissioned Concept to undertake this complementary analysis (discussed below).

4.11 Our analysis was based on the expectation that in a competitive market, prices should reflect – although not necessarily equal – SRMC (Grant Read seems to suggest that we were implying perfect competition outcomes as a benchmark – ie, prices equal to SRMC). This relationship should remain consistent over time. If this relationship holds, prices will reflect underlying conditions.

4.12 Our analysis assumes that SRMC is inclusive of opportunity costs and scarcity rents. We acknowledge the difficulties inherent in this analysis due to the difficulties in measuring SRMC (and the subjective nature of opportunity costs). Conditions which affect risk assessment – such as gas supply uncertainty – should be reflected in these opportunity costs. We acknowledged in the WMR that our measures of opportunity cost may not perfectly take gas supply uncertainty into account. The level of risk aversion surrounding this gas supply uncertainty is also subjective. We therefore cannot be certain if any change in relationship between SRMC and offer prices in the review period compared to previous years was a change reflecting this gas supply uncertainty. This is discussed in the previous section.

4.13 As the Independent retailers pointed out, we need to consider what the status quo will mean for levels of competition over time. MDAG also discuss how competition is vital for the transition to 100% renewable electricity:[11]

Participants' willingness to commit the necessary capital at the right times will be strongly influenced by signals in the wholesale electricity market. If the signals are not clear, investors may be deterred or defer decisions, leading to a supply gap and unreliable supply. Conversely, if signals are distorted or too strong, investment could occur in more expensive options or be premature – both of which would raise costs for society.

And:

Without effective competition, consumers and policy makers will not have confidence in electricity spot or contract prices. Without that confidence, investors are unlikely to commit the sums needed to underpin the shift to 100%RE.

[10] Noting that the SCP framework does include longer-term components also. It explicitly considers incentives for and barriers to entry (and exit) and dynamic efficiency.

[11] Pages 75 and 103: https://www.ea.govt.nz/assets/dms-assets/29/01-100-Renewable-Electricity-Supply-MDAG-Issues-Discussion-Paper-1341719-v2.4.pdf

4.14 This implies that the correct price signals – and confidence in those price signals - are needed now, to efficiently transition away from fossil fuels.[12] Therefore, prices that reflect SRMC are also important, not just whether prices will reflect LRMC in the long-run. Stephen Batstone points out that ""it is important to recognise that the long-term incentives required for the set of investments that are required to support 100% renewables markets are critically dependent on the signals that arise from ancillary, spot, and contract markets – as Hogan (2013) observes, the long-term is a succession of short-term markets".[13] Prices that reflect SRMC will also continue to be important in the future, during the transition and once thermal generation retires, especially as the system becomes more reliant on demand flexibility and batteries. These demand-side resources need the right information to plan ahead (in the short-term, ie, get batteries ready so it can discharge or charge as needed) and to be able to react in real-time as needed.

The SCP framework analysis informs whether the energy trilemma objectives may be realised

4.15 For the WMR we have focussed on assessing the competition limb of the Authority's statutory objective. However, the Authority's 2020 Strategy reset recognised that as the regulator of the electricity industry, our work also provides a platform for the country to achieve its aspirations for enhanced quality of life, prosperity and environment. While the SCP framework analysis focussed on assessing competitive outcomes, it also sheds light on whether the New Zealand electricity market is set up to contribute to these wider aspirations. The right price signals are needed to achieve the orderly retirement of thermal generation and to achieve all three aspects of the trilemma: security, sustainability and affordability. If competition is effective the right price signals will occur for renewable generation investment and prices will be affordable for electrification to occur.

4.16 Mercury and Contact argued that the NZ electricity market has delivered – and continues to deliver – very good outcomes in terms of balancing the energy trilemma. Mercury said significant investment is occurring and barriers to entry are low. Contact said that NZ is the only country outside of Europe to achieve an AAA rating across all three metrics of the World Energy Council's energy trilemma scores.

4.17 However, NZs overall World Energy Council score has fallen since 2000 by 3 percent, and our security score by 5 percent. NZ is also not in the top ten countries for the energy equity score.[14] This suggests NZ is slipping when it comes to continuing to deliver the best outcomes for the trilemma.

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[12] Grant Read (An Economic Perspective on the New Zealand Electricity Market, 2018, https://www.mbie.govt.nz/dmsdocument/4195-meridian-energy-electricity-price-review-first-report-submission) also appears to agree with this, stating "Alignment between prices and SRMC is still theoretically desirable, inasmuch as it provides more accurate signalling for efficient operation, both within the sector, and to consumers." Yarrow and Decker also state that efficient dispatch (ie, allocative efficiency) "…have implications for other decisions such as plant availability and longer term investment decisions." (pg 8 in "Bidding in energy-only wholesale electricity markets" November 2014).

[13] https://www.ea.govt.nz/assets/dms-assets/29/02-Literature-Review-of-Price-Discovery-with-100-Renewable-Electricity-Supply-Dr-Stephen-Batstone1341581-v2.1.pdf

[14] https://trilemma.worldenergy.org/

4.18 Additionally, the investment study undertaken by Concept suggests that investment is not occurring at the scale and pace needed to achieve an appropriate balance of security, sustainability and affordability in electricity supply. This is discussed in the next section.

4.19 Mercury said that the Authority should use a trilemma framework instead of the SCP framework, as "The most pressing short-term issue is achieving the orderly phase-out of thermal generation while maintaining security of supply, affordability, investment signals and efficient market operation." While the trilemma framework is important and useful, it is not designed to investigate whether competitive outcomes are occurring.

But we also looked at competition in the longer-term

4.20 Given the threat of entry by new firms can significantly constrain the behaviour of existing firms, we also consider longer-run competitive dynamics by assessing the ability of developers to enter the wholesale market. To do this the Authority commissioned Concept Consulting to assess the pipeline of new investment and compare this against the quantity of new generation needed to meet projected increases in demand and economic displacement of thermal generation.[15] We also asked Concept to determine what conditions exist that may potentially prevent, impede, or slow entry into the market.

4.21 Concept estimates that to meet projected increases in demand growth[16] and the economic displacement of thermal generation, approximately 6,200 GWh/year of new generation will be needed by the end of 2025. This compares to about 3,000 GWh/year of new projects currently committed for commissioning by 2025. Based on interviews and public sources there is a further 8,100 GWh/year of actively pursued generation projects that could be completed by 2025 if everything went to plan. Concept estimate that 40 percent of these known projects would need to be converted into actual developments to fully meet projected demand and the estimated economic retirement of thermal generation by 2025. This would imply an average of 1,200 GWh of development per year, which is almost 400 percent of the historical rate of development. If new development does not achieve the 'target' rate, that will mean higher than economic use of thermal and prices above the long-run cost of new supply.

4.22 Key factors that could affect the likelihood of projects being committed (i.e. lift the conversion rate) or increase the volume of potential projects (i.e. to offset attrition) include:

(a) Overseas Investment Act 2005 (OIA 2005) consents.

(b) Tiwai uncertainty (still relevant but appears to be less of a handbrake on new development than it was 12-24 months ago).

(c) Incumbent developers' incentives and access to firming products for independent developers.

(d) Awareness of NZ from overseas developers.

[15] Economic displacement of thermal generation refers to the volume of fossil fuel generation (excluding co-generation) that is estimated to be economic to displace based on forecast carbon and fuel prices in 2025 and projected cost of new renewable supply (assumed to be 84 $/MWh on a firmed basis.

[16] Demand growth projections are based on the mid-point of *Measured Action* and *Mobilise to Decarbonise* cases in the Whakamana te Mauri Hiko report by Transpower.

(e) Some other factors such as the Resource Management Act 1991, strained supply chains, elevated build costs, and connection queues.

4.23 These factors are discussed in more detail in Concept Consulting's Generation investment survey 2022 and in our companion paper.

4.24 The amount of new generation in the pipeline that has been committed or is being actively pursued for completion by 2025 by independent developers (ie, those outside of the major four gentailers) is about 70 percent. It is encouraging that independents are entering to compete in the development of new generation.

4.25 However, while there is no strong evidence of anti-competitive behaviour *for* the market – which is encouraging for competitive pressure on existing generators - the potential for competition *in* the market to be lessened in the future remains a concern:

(a) ASX forward prices are forecast to remain higher than the long-run cost of new supply at least until 2025 (suggesting existing market power may not be addressed by the current rate of new entry)

(b) The structure of the market will remain such that it is dominated by the four major generators, and they will control the vast majority of flexible generation.

4.26 To illustrate, we have presented possible HHI and gross pivotal figures for different scenarios of ultimate ownership of the new generation investment in Table 2 below. If the major four gentailers develop all of their actively pursued projects and the residual need (of the 6,200 GWh/year) is met from independent developments, independent development will make up 40 percent of this new generation. If all of the independent development is ultimately owned and operated by independent generators, this would mean 17 percent of total generation was owned and operated outside of the major four gentailers in 2025 (compared to 14 percent today). At the other extreme, if the residual need (once committed projects are accounted for) is met entirely from independent developers actively pursued projects, independent development could make up 62 percent of this new generation. If all of the independent development is ultimately owned and operated by independent generators, this would mean 20 percent of total generation was owned and operated outside of the major four gentailers in 2025. There is also a possibility that some or all of the independent developments would ultimately be bought by an incumbent. Scenario 3 models the outcome if all new developments were bought by one of the four major gentailers. In this scenario total generation owned outside the major four generators would decrease (as thermal generation owned outside the big four is displaced by new generation) resulting in 11% of total generation being owned outside the major four gentailers. These estimates would result in an HHI of between 1800 and 2200 in 2025 – a slight decrease or increase compared to what it is currently.[17]

[17] These figures are based on 6,200GWh of new generation and 4,000GWh of thermal retirement. 2021 generation was used as the base case. We ran three scenarios: 1. The major four gentailers build all of their committed projects and the remainder is built (and ultimately owned) by the independent developers. 2. The major four gentailers build all of their committed and actively pursued projects and the remainder is built (and ultimately owned) by the independent developers. 3. One of the major four gentailers buy any of the independently developed generation. The lowest HHI is equal to 1830 under scenario one, and the highest is equal to 2160 under scenario 3 if Meridian was the gentailer to buy all of the independent developments.

Table 2: HHI and gross pivotal from different scenarios of new generation ownership

Scenario	Percent of new generation from independent developers to 2025	Total generation owned outside of the major four gentailers 2025	HHI 2025	HHI 2030+ (most proposed generation developed and thermal generation fully displaced)	Estimated time Meridian is gross pivotal 2025 (%)
Base scenario (2021 generation fleet)	-	*5,800 GWh/year* *(14% of total)*	*2020*	-	*75+*
Scenario 1: The four major gentailers develop all of their committed and actively pursued projects, and independent developers make up the remainder of the 6,200GWh	40	7,500 GWh/year (17% of total)	1940	1290	80-95
Scenario 2: All committed projects are developed and actively pursued projects from independent developers make up the remainder of the 6,200GWh	62	8,900 GWh/year (20% of total)	1830	1220	80-95
Scenario 3: One of the four major gentailers buy any independent developments	0	5,000 GWh/year (11% of total)	2160	2310	95

4.27 Therefore, it appears unlikely under current market conditions that any new independent generators will be able to achieve the scale and flexibility required to substantially change the market structure (given the factors listed above), at least to 2025. Further into the future, even if all of the projects in the pipeline get developed (44,890 GWh/year post-2025), these projects ultimately end up being controlled by the developer and, assuming no current thermal plants remain in the market, the major four gentailers would control about 50 percent of total generation. Additionally, they will still control the vast majority of flexible generation given the majority of the pipeline of new investment by independent developers is solar.

5 There was more agreement that prices are higher than LRMC, although conflicting views on whether the market will correct this by itself or not

5.1 Overall, we found that submissions agreed that prices since the Pohokura outage are higher than LRMC. Some submitters said that this was a feature of energy-only markets and that prices would fall closer to the LRMC as new investment entered the market, while others believed that market concentration or some other barrier to entry could mean high prices will persist.

5.2 Meridian, Trustpower and BEC all argued that the market would correct itself in the long term. These submissions discussed how prices may vary from the cost of entry for long periods due to lumpy investment, and that lags in investment mean it takes time for prices to fall back to LRMC. These submissions argue that it is entirely reasonable for prices to be greater than LRMC for a sustained period of time in energy-only markets (with no scarcity payments, capacity market or subsidies), and a sustained period of prices above LRMC is necessary to attract new investment. Meridian discussed how there are legitimate reasons as to why investment has slightly lagged behind higher wholesale prices including consenting, construction times, demand uncertainty due to Tiwai, uncertainties around transmission costs due to TPM reform, uncertainty over thermal fuels and decarbonisation, and government policy and regulatory uncertainties.

5.3 Hayden Green (Axiom Economics, included as part of Meridian's submission) argued that if prices are above LRMC for prolonged periods this may indicate barriers to entry, but it is necessary to consider whether current market outcomes are perpetuating or self-correcting.

5.4 Mercury said that the sector is responding strongly to market signals and the investment environment is improving. They said that the SRMC of renewable generation will contribute to lowering the average wholesale prices as new generation projects are commissioned, although volatility in prices is likely to continue as the amount of intermittent renewables increases. However, they also advocated for reforming the resource management framework to support decarbonisation and said that streamlining the resource consent process would have material benefits in terms of ensuring competitive outcomes.

5.5 Nova said that in the long term high prices should result in additional competition from new generation capacity, but the expected closure of the Tiwai aluminium smelter created increased risk for parties considering building new generation capacity.

5.6 Independent retailers said that a continued or increasing exercise of market power undermines confidence in the market which in turn undermines investment, particularly from potential new entrants, and results in further consolidations and protection of incumbency advantages.

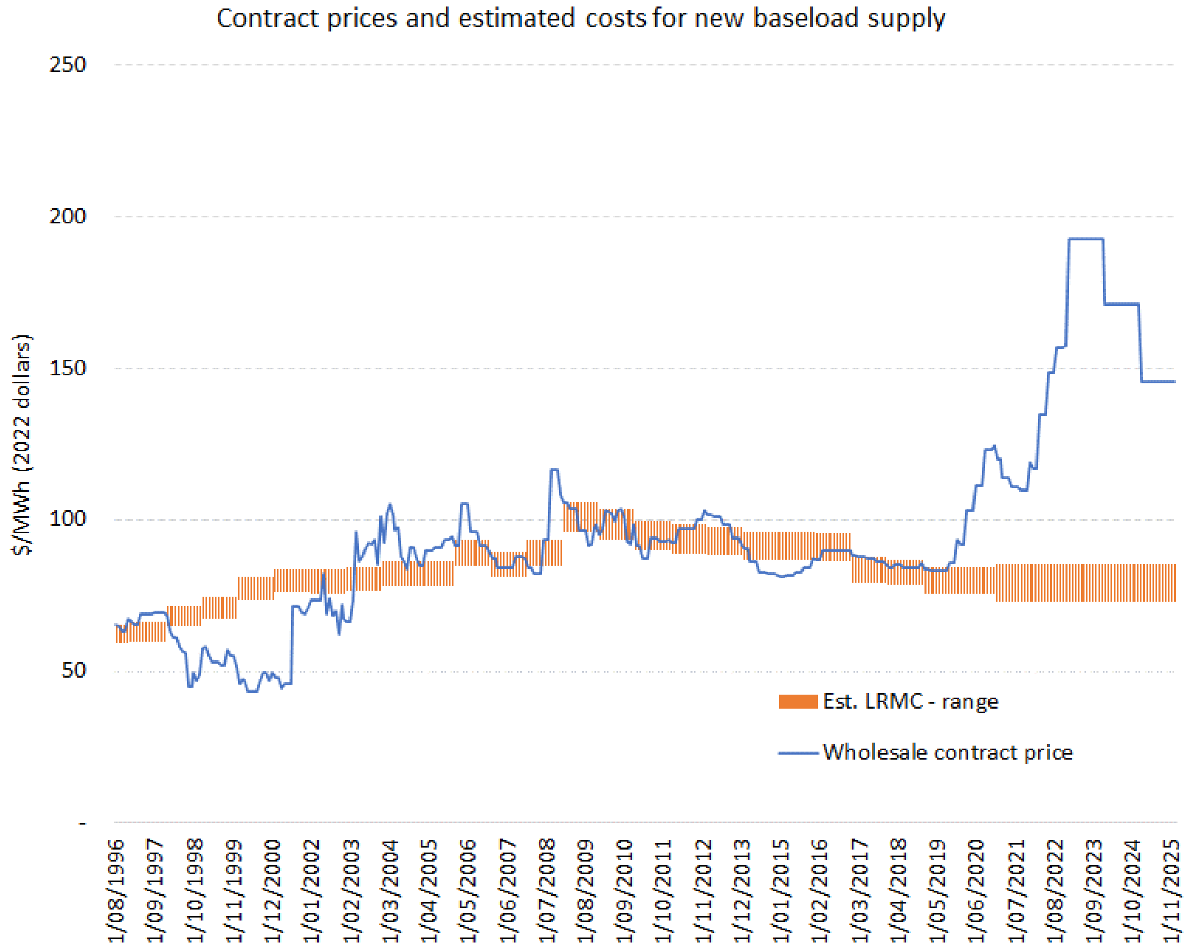
5.7 Winston Pulp argued that current and anticipated wholesale electricity prices are well above levels justified by the LRMC of available generation technologies and what would be expected in a well-functioning market.

5.8 We agree with some submissions that there could be a sustained period of time when prices are higher than LRMC, although prices should still reflect SRMC (SRMC is expected to be higher than the cost of entry during times when the market is signalling the need for more investment, as more expensive plant with higher SRMCs will be dispatched – and therefore set the price – more often to meet demand. Due to the time lags involved in building new plants these higher-cost plants will not be replaced by lower-cost plants immediately). We also agree that there have been some conditions in the market – such as the uncertainty surrounding Tiwai – which may have delayed investment in the past.

5.9 However, much of the uncertainty has diminished to a large extent[18] and prices have been above LRMC for over 3 years now (see Figure 1). While we agree that prices above LRMC for a prolonged period does not require an abuse of/sustained exercise of market power (due to lumpy investments and the uncertainties that existed in the market), the Authority was concerned to understand whether the duration and extent of the departure indicated the presence of market conditions that prevent, impede, or slow entry into the market. We commissioned Concept to investigate why prices are higher than LRMC, and whether this can be expected to self-correct. Concept found that there are market conditions which exist that suggest new development may not achieve the 'target' rate of new generation development. This may mean higher than economic use of thermal and continued prices above the long-run cost of new supply – at least until 2025. Concept observed that one reason the market may not self-correct may be due to the incumbents and 'portfolio effects'. That is, the four major generators face some potential cannibalisation of revenues from existing assets when new projects are commissioned, and as such this may dampen their development incentives. This may indicate a lack of competition and engagement from the major generators in the PPA market. While there were mixed reports that this may be a problem and it was not possible to definitively test the strength of such claims, based on underlying incentives Concept suggest this area merits closer monitoring.

[18] Meridian agrees with this, see page 77 of its submission.

Figure 1: Forward contract prices versus LRMC



Source: Concept Consulting

6 The Authority does not consider there were any issues raised by submissions or additional indicators suggested by submitters that would materially change its observations

Submitters ideas around using a different framework for the analysis run into similar issues

6.1 There were varying opinions on the SCP framework that we used for the analysis. Neil Walbran and Flick supported the use of the SCP framework for investigating competition issues. Alternatively, some submissions thought the SCP framework we used was the wrong framework and we should use a perfect or workable competition benchmark and compare actual outcomes to this benchmark. However, similar to the SCP framework analysis, this type of analysis also does not provide a definitive answer on whether generators have been exercising market power.

We do not assume perfect competition as our benchmark

6.2 Some submissions (EPOC, Meridian, Independent retailers) said that we should use a benchmark of perfect (EPOC) or workable (Meridian, Independent retailers) competition and compare outcomes to this benchmark. Meridian said that we had no clear benchmark and needed to define this better.

6.3 We agree with Meridian and Trustpower that we should not expect perfectly competitive outcomes. Trustpower said that it "seems wasteful to need to determine if prices are always perfectly reflecting underlying conditions – if prices were easily predicted, what value is a market?". However, our analysis was never designed to determine this – we expect prices to *reflect* underlying conditions in a consistent way. We do not assume the market should achieve the theoretical goal of perfect competition.[19]

6.4 We also do not use the comparisons to DOASA water values in the way in which EPOC suggest. Its approach would involve quantifying the difference between perfectly competitive outcomes and actual outcomes. The resulting perfectly competitive outcomes also rely on assumptions as with any analysis. And as discussed in the EPOC submission, "Some caution is needed in drawing conclusions about motives of market participants from counterfactual models. Exercise of market power is commonly blamed for deviations from perfectly competitive outcomes, but other factors might have caused these." In other words, this comparison would run into the same issues we faced in our analysis – it cannot provide a definitive answer of whether market power has been exercised.

6.5 We use DOASA water values as a consistent measure of the opportunity cost of water. We do not expect generators to offer at this water value.[20] However, we do expect a consistent relationship between generator offers and the DOASA water value over time and between generators. The DOASA water values should incapsulate underlying conditions and as such generators offers – in a competitive market – should be related to these water values. However, we reiterate that water values are sensitive to assumptions and all calculations of water values involve subjective judgements. These problems with estimation and the fact that DOASA water values represent a perfect competition outcome are why we have not used the DOASA water values as a benchmark to achieve.

6.6 Meridian said we need to define our benchmark better. We do not think a single benchmark exists for multiple indicators. We have however set out our competitive expectations for the market.

6.7 To set out our expectations for the market, we do not use a modelled benchmark counterfactual. Rather, we compare indicators between generators and over time, to see if there is a consistent relationship between offers and underlying conditions, and between offers and costs. As mentioned above, this involves judgements about what we expect to see as competitive outcomes. We could alternatively do as suggested by Electric Kiwi and Haast and model expected outcomes for workably competitive markets. But this exercise would also involve judgements and many simplifying assumptions and a choice about how to implement the concept of workable competition over multiple indicators. Any "optimal configuration" from such modelling would be widely debated.

[19] Perfect competition is a theoretical construct that has pedagogical value but otherwise is of no practical use.

[20] We have also used historical water values which are calculated using actual fuel costs, generation and HVDC outages and reconciled load. These historical water values would not be what generators would calculate at the time they are making decisions about their offers (as they would be forecasting future fuel costs, outages and load).

Setting out our qualitative expectations of the market for each indicator (and assessing relative changes to these expectations over time) is a more transparent and straight-forward way to achieve what will always be a non-definitive judgement-based analysis of competition in the wholesale market across a range of indicators.

Submitters raised issues with our interpretation of the indicators and thought we left out important indicators

Structural indicators

6.8 Table 3 discusses our response to points raised in submissions on the structural indicators we used in the WMR.

6.9 While we agree with Trustpower that "the existence of market power does not of itself indicate that market power is being exercised", it is also true that if the structure is such that all generators have a small market share, then no generator would be able to exercise market power very often or for very long. Structural indicators therefore give us some insight into the underlying characteristics of the market and the ability of generators to be able to exercise market power. While it may not be surprising that the generation market in New Zealand is highly concentrated – given the small size of New Zealand and how the market has developed over time[21] – it is still important to understand the structure – both now and in the future as we transition to 100 percent renewables – to provide useful insights into the strength of competition. Furthermore, our analysis of the structure of the market is just one aspect we assess. We also consider other relevant factors to assess the extent of competition. Once we understand the structure and ability for generators to exercise market power, the conduct and performance indicator analysis can then help determine whether any of these generators are exercising that market power.

[21] Along with the other reasons as set out by Trustpower in its submission.

Table 3: Structural Indicators

Indicator	Our assessment in the review	What submitters said	Our updated assessment
Generation HHI	HHI for generation is of limited use because it is driven by storage, and storage over the review period has been low a lot of the time. This has meant that the HHI has fallen at times during the review period, but this may just be due to drier conditions. It remains around 2000, as it has done since 2014.	Electric Kiwi and Haast said there are signs market concentration is worsening, especially in the South Island. They also suggested forecasting HHI for the next decade. Meridian said the longer term trend shows HHI very gradually falling. The Independent retailers thought that the seasonal variability can be resolved by looking at long-term trends. Several submitters thought this indicator should be green. BEC said that seller concentration is of limited use in addressing electricity market intricacies. MEUG's submission agreed this was of limited use but stated NZ has a high concentration of generation compared to UK or Australia. Several submitters thought concentration ratios should be included.	We agree with the Independent retailers that the HHI is a useful indicator in the long-term. That is, we should focus on the trend and ignore short-term fluctuations due to changes in storage. The updated HHI chart shows that the long-term trend is no longer decreasing – it was decreasing prior to 2012 but has since flattened out. HHI still remains around 2000 as at 31 May 2022. While we agree with the BEC that this indicator alone does not address the intricacies of the electricity market, it is an indicator of the structure of the market and is presented alongside a suite of indicators (using the SCP premise), from which we look at the overall picture. The impact of new investment on HHI will depend on who ultimately ends up owning the new generation. New investment from the current largest players, or new investment by independent developers that ends up being owned by the incumbents, could worsen HHI. Based on the current pipeline of new investment put together by Concept Consulting, we estimate the HHI could be between 1800 and 2200 in 2025, and between 1200 and 2300 from 2030. Concentration ratios (CR) show a similar story to HHI.

Gross pivotal	Meridian has historically been gross pivotal around 77 percent of the time, but in the review period this had increased to around 90 percent to 95 percent	Some submitters said the pivotal results were unsurprising given the timeframe, market structure and fuel availability, and does not indicate distortion of outcomes. Several submitters also suggested the Authority should use net pivotal either instead of, or as well as, gross pivotal, as gross pivotal does not indicate the incentive to exercise market power. MEUG notes that this only shows market power has increased but not how the exercise of market power has changed. Meridian said that we should include available but unoffered generation, and that it is unclear why the Authority considers the South Island as a separate region. It also said the increase in gross pivotal over the last few years is due to an increase in South Island load, a decrease in offered thermal generation, and limited investment in South Island baseload plant. Carl Hansen (Capital Strategic Advisors, included as part of Meridian's submission) discussed how the review used the gross pivotal concept without considering its applicability to the NZ system, which has a large share of must-run generation.	Gross pivotal is an indicator of the structure of the market, whereas net pivotal is an indicator of the incentive to exercise market power when a generator is gross pivotal. The gross and net pivotal measures that the Authority uses are based on simulations where the total quantity of the participants' offers are priced at $30k. While this is sensible for the gross pivotal measure, it makes the net pivotal measure less useful. This is because in reality a generator will try to get the biggest price response from the smallest change in volume (from lower priced tranches to higher priced tranches). However, our net pivotal measure simulates the maximum volume response – ie, changing *all* of a participants' generation offers to $30k and therefore minimising the quantity they are dispatched for. The 4 largest generator-retailers in NZ are often long on generation (net physical position).[22] This means that they probably benefit financially often in the short term from receiving a higher price for their generation.[23] Additionally, even if the generator is short on generation (ie, it needs to buy more generation than it generates itself to cover its purchases and contracts), generators have a longer-term incentive to increase spot prices, as higher spot prices will normally be reflected in the

[22] Discussed in https://www.linkedin.com/pulse/market-power-new-zealands-wholesale-electricity-critique-hayden-green/. We calculate that Contact was long 100 percent of the time over the review period, Genesis 73 percent, Mercury 57 percent and Meridian 54 percent.

[23] Biggar (2011) also discusses how the incentive to exercise market power depends on how much of the generators' capacity is needed to meet demand. https://www.aemc.gov.au/sites/default/files/content/1b0947b4-930f-449a-be21-4cf009b2fe7a/AER-Attachment-1.PDF

		The Independent retailers said that the gross pivotal results provide evidence of substantial problems with competition.	contract prices the generator-retailers are prepared to accept.[24] An increase in South Island load affects the entire market. The gross pivotal measure does not treat the electricity market as separate regions (islands), but rather separates a generators' offers by North and South Island in the simulations. This is because all of Meridian's and Contact's hydro generation is in the South Island, all of Mercury's hydro generation is in the North Island and all of Genesis's and Contact's thermal generation is in the North Island. Therefore the label "gross pivotal in the South Island" was used to clarify the location of the plant that was pivotal, rather than stating the conclusion that the plant was only pivotal in the South Island. All transmission constraints are treated the same as they are in final pricing. A decrease in offered thermal generation due to fuel availability reflects the changing structure of the market. While outside Meridian's control, it still results in Meridian's generation being needed to meet demand more frequently, and therefore has an impact on Meridian's ability to exercise market power. It also gives an indication of what may be expected for the gross pivotal indicator once thermal generation starts retiring and is replaced by intermittent generation. We do agree, however, that some unoffered generation may be being physically withheld with

[24] Discussed in https://www.linkedin.com/pulse/market-power-new-zealands-wholesale-electricity-critique-hayden-green/.

			the express purpose of trying to increase the spot price (similar to economic withholding). This unoffered generation should be included in any measure of gross pivotal. It is hard, however, to know what proportion (if any) of the unoffered generation is being used in this way, or is simply due to fuel availability or other operational constraints. Carl Hansen raised that we should take into account must-run generation, ie wind, geothermal and hydro generation needed to meet resource consents. The simulation to calculate gross pivotal excludes wind and geothermal from the calculation,[25] which makes up the majority of "must-run" generation. To account for the impact of "must-run" hydro generation on the gross pivotal results, we looked at the percentage of time that each generator was gross pivotal when we removed trading periods where the megawatts needed from the generator to meet demand was less than 20 percent of the generator's total capacity.[26] Meridian was still gross pivotal 23 percent of the time in 2019, 56 percent of the time in 2020, and 72 percent of the time in 2021 (to June) (compared to around 20-30 percent in the previous three years).

[25] From September 2019 wind is treated the same as other offers. That is, it is increased to $30k along with the other offers from the generator. This will not affect the calculations for Meridian much as it only has 58MW of wind in the South Island, but may affect Mercury's results once Turitea became operational.

[26] Twenty percent is an overestimate of the must-run quantity on the Waitaki. With minimum flow requirements down the Waitaki of 150cumecs, this would imply total generation from Benmore, Aviemore and Waitaki of 194MW (less than 10 percent of the total Waitaki chain capacity, calculated using plant factors of 1.223, 3.225 and 6.165 respectively). Over the review period, the minimum quantity of Meridian's offers priced at below $1/MWh on the Waitaki was 16.5 percent of the total offered.

			These calculations are equivalent to adding another 470MW of thermal generation (which is over 20 percent of existing thermal generation). This is probably an overestimate of how much extra thermal generation could be available but not offered (and an overestimate of the "must-run" generation on the Waitaki), and therefore an underestimate of the percentage of time Meridian is gross pivotal once unoffered thermal generation (or "must-run" generation) is accounted for.
Vertical integration	While Mercury and Contact's level of vertical integration has decreased (based on our measure), Meridian's has increased. The level of vertical integration remains high in the New Zealand market. Some indication of increased use of PPAs and potential PPAs means vertical integration is less of a barrier than it might have been.	Several submitters said that vertical integration (VI) is useful for risk management and funding investments and removing VI would not reduce prices and could disrupt the investment cycle. Hedges are available to non-VI generators. Investment was occurring which showed this is not an issue. Conversely, several submitters said that VI reduces competition as gentailers control the derivatives markets and provide themselves with better terms via internal transfers than they provide to independent retailers. Paua to the People said that VI offers little incentive to invest in low emission generation and MEUG said the Authority should consider whether market power of VI is a barrier to entry. Meridian argued that it is not surprising that incumbents often account for a high share of new investment projects, so this is not an indication of barriers to entry. It	Concept has undertaken further work looking at the pipeline of new generation investment and whether there are any barriers to entry for new generation. They found that it is unclear whether the large incumbent suppliers are seeking to prolong the period of high prices through their treatment of independent developers. Some responses suggested independents found it hard to attract interest from the major generators, even with apparently attractive projects/power purchase offers. However, many international developers said that access to PPAs is not a prerequisite for development. Therefore, the nature and extent of the problem remains unclear. As suggested by Concept the Authority plans to closely monitor this. The Authority introduced new provisions in the Code mandating the annual disclosure of mass market internal transfer prices (ITP) by integrated generator retailers, the methodology used to derive them and the disclosure of retail gross margin reports by certain retailers. The new Code

		also said that VI has not changed – if anything it shows a slowly decreasing trend. Possible improvements or solutions proposed by submitters included a transparent internal transfer price, introducing arm's length trading, or a market restructure to split generation and retail, similar to telecommunications.	provisions came into effect on 30 November 2021.[27] While overall the total level of VI may have been slowly decreasing with new entry by independent retailers, Meridian's level of VI has been increasing, and Genesis and Mercury's levels have remained similar since 2014 (with an expected increase in Mercury's level now that it has acquired Trustpower's residential and SME customer base). These individual company VI levels are pertinent as an indication of changes to market conditions that could be symptomatic of barriers to entry for new independent generation.

[27] https://www.ea.govt.nz/development/work-programme/risk-management/internal-transfer-pricing-and-profitability/

Conduct indicators

7.1 Table 5 discusses our response to points raised in submissions on the conduct indicators we used in the WMR.

The WMR focussed on the sustained exercise of market power, but we are interested in both transitory and sustained exercises of market power if they are significant

7.2 Meridian argued that the exercise of market power needs to be sustained to be of interest, but then conflate "sustained" with "continuous". While the analysis set out using the SCP framework in the WMR was concerned with detecting or investigating the sustained exercise of market power, the Authority is concerned with any exercise of market power – whether sustained or transitory – if it is "significant". Transitory exercises of market power could also indicate a more pervasive problem. The weekly monitoring and frequent further analysis undertaken by the Authority's Market Monitoring team assesses potential transitory periods of the exercise of market power. The analysis using the SCP framework complements that analysis by presenting indicators over a longer time horizon that are more useful for assessing the sustained exercise of market power. We plan to regularly update and release the SCP analysis presented in the WMR.

We have not changed our view on the possible presence of economic withholding

7.3 There were mixed views around our analysis of economic withholding. Meridian stated that what we framed as potential economic withholding is in fact a conversation about prudent storage management and risk aversion in a market with gas supply uncertainty. On the other hand, the Independent retailers said there is evidence of increased incentive for generators to use economic withholding to increase the price.

7.4 Grant Read (EGR Consulting) and Carl Hansen (Capital Strategic Advisors) (included as part of Meridian's submission) argued that there is no withholding by hydro generators as the water has to go downstream at some point, so the only way for them to withhold is to spill. This ignores the flexibility that hydro generators have to change the timing of water flows – they could be withholding when prices are lower (so prices in these trading periods increase relative to the competitive outcome) but release more water (relative to the competitive outcome) when prices are higher. They may also only need to withhold a small amount to affect prices.[28]

7.5 Grant Read also argued that New Zealand does not have a market for offering flexibility (ie, the ability of a generator to respond to fluctuations in supply and demand). Therefore the higher-priced offers in the wholesale spot market are being used to offer this flexibility service, so economic withholding is moot. Carl Hansen also makes this point in relation to Pukaki, as does Mercury in its submission. Hansen argues Meridian offers capacity on the Waitaki at high prices so that it is only dispatched for peaking and last resort purposes, so it does not make sense for these higher-priced offers to vary in response to changes in seasonal conditions. However, a hydro generator's ability to offer this flexibility/capacity service decreases when storage is high. That is, as storage gets high, the generator must release water to prevent spilling. They cannot keep

[28] This point is also relevant to Meridian's argument that the very close correlation between actual generation and modelled optimal volumes is evidence that the unexplained uplift in prices is not due to the exercise of market power. A close correlation could also be achieved with small changes in volume which affect prices.

offering this flexibility indefinitely. We therefore still expect that the percentage of higher priced offers should decrease when storage is high.

7.6 Carl Hansen also argued that setting higher offer prices is only meaningful if it increases spot prices, and therefore examining offers above final prices (and above $300/MWh) is meaningless (as not all higher-priced offers affect the spot price). The 2 percent decrease in demand in the South Island indicator showed that these higher-priced offers often have an impact on prices (a 2 percent decrease in demand is equivalent to an increase in supply at prices lower than the final price – ie, moving some high-priced offers to lower prices). The results also showed that the effect on prices has been increasing over time.

7.7 Meridian also argued that the Authority – by excluding physical withholding – has created the perception that we would prefer physical withholding over economic withholding. This is not true. Our reasons for focussing on economic withholding include:

(a) Thermal generators need time to heat up. For example, TCC takes three days to warm up. In contrast, hydro generators can generate instantly with unused quantity if needed. This means hydro generators have more capability of offering higher-priced offers to indicate available-if-needed quantity.

(b) Similarly, reduced gas availability may keep thermal generators' energy offers below full technical capacity.

(c) Thermal generators have always had a high percentage of unoffered generation (compared to hydro generation), but this was lower on average in the review period compared to previous years.[29] Only the thermal peakers had an increase in the percentage of offers above SRMC in the review period, which could be consistent with gas supply risk.

(d) Thermal generation holds less market share than hydro generation in the NZ market, especially thermal peakers which are more capable of turning on and off quickly.

(e) Gas supply uncertainty makes it difficult to assess whether thermal generators were physically withholding (to impact the price) or could not run due to fuel supply constraints or other operating constraints. While this is a similar problem to assessing economic withholding versus prudent storage management and hydro operating constraints, we have less transparency of fuel availability for thermal compared to hydro. This is not ideal but remains a problem for analysis of thermal offers.

(f) Hydro generators only have a small proportion of unoffered capacity on average.[30] However, we calculated our indicators including unoffered generation for the hydro generators to check the impact of unoffered generation. We followed Meridian's analysis and put the unoffered capacity (where not indicated as an outage on POCP) to $301/MWh. The results are presented in Appendix A. The results show

[29] Once adjusted for outages (as shown on POCP), Contact (Stratford) and Genesis (Huntly) had approximately 20 percent and 30 percent respectively on average not offered during the review period (compared to nameplate capacity). For 2014-September 2018 these figures were approximately 40 percent and 35 percent respectively.

[30] Meridian (Waitaki), Contact (Clutha), and Genesis (Tekapo) all had around 0 to 10 percent on average unoffered capacity once adjusted for outages on POCP, while Mercury (Waikato) had about 20 percent on average (compared to nameplate capacity). These percentages were similar for 2014-September 2018 and the review period (2019-June 2021).

a similar story to that presented in the review. That is, Meridian (Waitaki) and Mercury (Waikato) have a higher percent of offers greater than $300/MWh, the maximum gas SRMC, and DOASA water values when hydro storage is higher, compared to Genesis (Tekapo) and Contact (Clutha).

7.8 Meridian said that our analysis of offer prices does not recognise generation portfolios, and that we should include Manapouri with Waitaki. We have not done this for other generators (eg, we have not included Contact’s thermal offers with its hydro offers), although we recognise that this is slightly different as Meridian is the only (large) generator with multiple large hydro schemes. We also note that the trading conduct rule applies to offers at each node. The results of including Manapouri offers with the Waitaki offers are shown in Table 4. The percentages for Meridian decrease for periods of high hydro storage once we include Manapouri, but remain higher than the percentages for Genesis (Tekapo) and slightly higher than the percentages for Contact (Clutha) except for the percentage above the average DOASA water value.

Table 4: Updated percentages of high-priced offers when Manapouri is included – review period (2019 to June 2021)

Indicator	Storage level	Mercury (Waikato)	Meridian (Waitaki)	Meridian (Waitaki and Manapouri)	Genesis (Tekapo)	Contact (Clutha)
Percent of offers above $300/MWh	Low hydro storage (less than 80% of mean)	50	33	30	29	40
	High hydro storage (greater than or equal to 100% of mean)	41	25	20	4	10
Percent of offers greater than SRMCs	Low hydro storage (less than 80% of mean)	36	36	33	33	41
	High hydro storage (greater than or equal to 100% of mean)	31	28	21	4	18
Percent of offers greater than DOASA water value	Low hydro storage (less than 80% of mean)	62	47	40	39	46
	High hydro storage (greater than or equal to 100% of mean)	55	35	26	5	29

Table 5: Conduct Indicators

Indicator	Our assessment in the review	What submitters said	Our updated assessment
Offers over time	Offer prices have been higher in recent years. It is not clear whether this is due to gas supply uncertainty, increases in costs, or generators exercising market power. It appears the some of Meridian's offer behaviours have changed following the UTS at the end of 2019. But it still has a large percentage of offers in its top tranche, even when storage is higher (and its offers over $300/MWh have been steadily increasing since 2014).	Some submitters said that changes in offers over time were consistent with low hydro storage, gas supply uncertainty and other market factors. Independent retailers thought offer prices were out of kilter with demand and supply conditions. Meridian said offers over time is uninformative and provides the same information as "offers above various benchmarks". Nova commented that the higher SRMCs of thermal generators gave hydro generators scope to raise offer prices without the risk of being displaced by thermal generation, while others argued hydro generators had to increase offer prices to ration water. Mercury discussed the impact market changes have had on their offer behaviour, including regulatory changes.	Offers over time are used as a visual aid, although we agree this indicator overlaps with other indicators. However, we are looking at the complete picture provided by the indicators and this visual aid helps present the picture. Nova's comment about higher SRMCs of thermal generators giving hydro generators scope to raise offer prices without the risk of being displaced is one of the scenarios the Authority believes is possible. However, we also agree that higher thermal costs can increase the opportunity cost of hydro generation and that hydro generators need to manage their storage, so it is difficult to ascertain if the increases in offer prices from hydro generators was due to higher costs or taking advantage of higher thermal costs. Mercury's comments highlight the need to get the regulatory settings right, to ensure offers are consistent with competition.
Percent of offers above cost	Meridian and Mercury always have a higher percentage of offers above cost compared with Genesis and Contact, regardless of the storage situation.	Several submitters said that either the DOASA water values were far too low or should be treated as a lower bound on the opportunity cost of water values. Many submitters also said the assessment of opportunity costs is highly	In the WMR we said that the DOASA water values could be considered a lower bound, and we have taken this into consideration when interpreting the results. Both DOASA and water values from generators are sensitive to assumptions, and the DOASA water values differ

	However, some of this may be explainable by gas supply uncertainty or hydro operating constraints.	subjective, and any calculations are sensitive to assumptions and perceptions of risk. Contact said that offer prices are likely to exceed SRMC due to high maintenance costs associated with thermal units being dispatched on and off in short timeframes. Grant Read (EGR Consulting, included as part of Meridian's submission) argued that the NZ market design means thermal participants will recover start-up costs by increasing their offers above SRMC, and massage offers to make sure they generate for long enough to recover them. Read also argued we should not expect something like pure marginal water value curves as 'fuel offers' under the NZ market design. Meridian said that the estimates of cost do not account for scarcity. Mercury said the increase in offer prices was due to cost increases and uncertainty, particularly in the gas market. It also said any non-baseload plant that can make discretionary capacity available flexibly will have a significant percentage of offers above cost. Several submitters said that the VWAP of gas is a poor indicator of the marginal	from the generator water values. We realise the subjective nature of opportunity cost estimation and discussed this in the WMR. However, DOASA is related to storage and provides a consistent measure by which to compare offers to. As most gas is supplied under contract, the Authority analysed gas supply agreements and found that the GSA VWAPs were similar to emsTradepoint gas spot price VWAP which gives us confidence that the VWAP used in this analysis is a good proxy for the cost of fuel for gas generators without storage. The electricity forward price is used as an estimate of the opportunity cost of storing gas. The SRMC used for thermal fuels includes overhead and maintenance costs. However, this is likely to best reflect the marginal cost when the unit is already running. Thermal generators usually offer some or all of their generation at a low price when they expect prices to be high enough to cover both the SRMC and the start up costs over the whole time the unit will be running and hope their low priced offers do not impact forecast spot prices. Additional generation available can then be offered at SRMC, depending on the kind of unit it is. As we expect thermal generation has always offered this way in the New Zealand market, we would still expect a consistent relationship between thermal generation offers and cost over time.

		cost of gas, as most gas is supplied under contract and there is some ability to store gas. EPOC said that offers below marginal cost are also suboptimal in a perfectly competitive setting. MEUG said the Authority should at least suggest some hypothesis for what percentage of higher offers is not explained by gas supply uncertainty or hydro constraints.	We agree that prudent storage management is necessary, and as a result we would expect to see more generation offered at high prices when storage is low and when there is gas supply uncertainty. We would expect, however, for the percentage of higher priced offers to decrease when storage is high. We also expect gas supply uncertainty and perceptions of risk to be reflected in opportunity cost measures, at least to some extent (although we realise this will be imperfect). We therefore expect a consistent relationship between offers and cost, but we saw an increase in the percentage of offers above cost in the review period for some generators. In periods of high hydro storage, cost will decrease and offer prices should reflect this decrease in cost. As mentioned above, hydro generators cannot offer flexibility indefinitely. We disagree that the estimates of cost do not include scarcity. Water value estimation takes into account storage and thermal costs, both of which are measures of scarcity. However, the estimated thermal costs may not accurately represent thermal fuel scarcity, and therefore the DOASA water values may also not perfectly capture scarcity.
Relationship of storage to cost	There were significant negative correlations for all generators in the review period, although slightly weaker correlations for Mercury (using its water	BEC pointed out that our analysis only considers hydro storage and not other fuel storage. MEUG said the Authority should comment on what other cost aspects are	Water is not a traded value, so we use hydro storage as a proxy for cost. On the other hand, thermal generators purchase thermal fuel through contracts, meaning injections of thermal fuel into storage may not be closely related to fluctuations in the opportunity cost of using this fuel. Finally,

	values) and Genesis (using DOASA water values). This indicate water values accurately reflect one aspect of cost for hydro generators.	driving hydro generator prices and what level of divergence between cost and market prices it would regard as evidence of market power when the generator setting the market price is gross pivotal.	thermal generators may have slightly more control over when they increase and decrease their storage levels compared to hydro generators.
Relationship of offers to cost	Meridian's and Mercury's offers are not correlated with their water values using some measures. None of the generators' offers appear to be related to the DOASA water values.	Meridian argued that the correlation of offers with costs can be meaningful only if the relevant offer tranches are included in the QWOP statistic, as high priced tranches are used for managing risk. It also argued that the low correlations of DOASA water values with storage indicates that the DOASA water values are not well calibrated to real world decisions faced by reservoir owners, making the DOASA water values misleading at best and invalid at worst. Nova argued that hydro generators are sculpting their offer profiles close to their expected supply commitments as a risk management policy. The hydro generators apply high prices to those offer tranches that are just above their expected load.	We expect all offers to be related to cost. That is, offer prices should decrease when costs decrease and vice versa. In a competitive market, we would expect a relationship between DOASA water values and offer prices. The trading conduct post implementation review found that offer prices now appear to be more closely related to costs – including DOASA water values – since the introduction of the new provisions.[31]
Lerner Index	Stratford has had a reasonably high average Lerner Index during the review period, higher than in	Meridian was concerned that only a Lerner Index equal to zero would be considered competitive by the Authority.	The Authority expects the Lerner Index to tend towards zero (although does not expect it to equal zero as we do not expect perfect competition). If we see Lerner values increasing over time – as

[31] See section 8 in *Post implementation review of the trading conduct provisions*.

	previous years. But this could be expected given that gas scarcity may not perfectly be factored into their cost. Meridian and Mercury had higher Lerner indices during the review period using DOASA water values.	Several submitters said that the Lerner index values are inaccurate due to inaccuracies in the estimate of marginal cost, eg our cost estimates do not account for all relevant opportunity costs, DOASA water values are too low, gas VWAP is not reflective of the marginal cost of gas, and our estimates of Stratford's costs are incorrect (as it runs less, Stratford will need higher prices to recover fixed costs over time). MEUG said the correlation between water values and offers by hydro generators overall and in particular at times when the generator has market power should be a key indicator of the likelihood that a generator is exercising market power. Carl Hansen (Capital Strategic Advisors, included as part of Meridian's submission) asserts that dispatch is rivalrous because the Lerner index is volatile. He also states that only the Lerner Index measures the price-cost relationship, so most of our other indicators which try to measure this are meaningless.	we did for some generators in the review period compared to previous years - this would indicate movements away from competitive outcomes. The Lerner Index is sensitive to the estimate of marginal cost used, as are all indicators based on marginal cost. For this reason multiple estimates of cost are used and analysis focused primarily on any changes to the Lerner Index, and not the value itself. Information from gas supply agreements showed that the GSA VWAPs are similar to emsTradepoint gas spot price VWAP which gives us confidence that the VWAP used in this analysis is a good proxy for the cost of fuel for gas generators. Rivalrous dispatch is expected to result in a lower Lerner Index value – including on average - rather than volatile results, as competition reduces price towards costs. We are also not asserting that generators must exercise market power in every trading period for it to be a sustained exercise of market power. If they are exercising market power regularly (but maybe not in every trading period) this would be a sustained exercise of market power. That is, it does not have to be continuous to be sustained. Volatility may also indicate the cost estimates relationship to actual costs fluctuates. However when we used DOASA water values there was less volatility during the review period compared to using the values provided by generators, and

			the Lerner Index was higher for Meridian and Mercury using the DOASA water values compared to previous years. Since the DOASA water values provide a consistent estimate of cost over time this indicated some cause for concern (when viewed alongside the results of the other indicators). In reply to Carl Hansen's assertion that our other indicators used to analyse the price-cost relationship are meaningless, we reiterate that generators can influence the price even when they are not marginal. The Lerner Index assesses the exercise of market power when a generator is marginal, as any comparison of the spot price with a generators cost must be analysed when the relevant generator is marginal. However, a generator can exercise market power through economic withholding regardless of whether they are marginal. Our other indicators are aimed at assessing whether economic withholding has been occurring.
2 per cent decrease in demand in the South Island	The simulations showed that the average price decrease (from a decrease in demand) was larger in the review period than in previous years. This could be due to the steeper supply curve (due to supply conditions)	Meridian said this indicator is based on an unrealistic assumption of no competitor reactions to a sustained change in supply. It rules out the most important aspect of workably competitive markets: rivalry. Carl Hansen (Capital Strategic Advisors, included as part of Meridian's submission) said that the 2 percent test is more likely to be measuring the consequence of greater uncertainty	The 2% decrease in demand test was included to understand if the generators had an incentive to withhold generation. When small changes in demand have a big impact on prices (ie, a steeper offer curve) there is more incentive to withhold generation compared to when the change in demand would only have a small impact on prices. Meridian's argument that this indicator is based on the unrealistic assumption of no competitor reactions is valid. However, this is true for all time

		about gas supply and tighter hydro conditions. Mercury said this only indicated a steeper supply curve, telling nothing about market conduct. MEUG said it would be useful to understand how the demand reduction affected the steepness of the price duration curve.	periods. Therefore the increase in price change observed during the review period compared to previous years does show that during this period there was increased incentive and ability to influence the price. Also, a 2% decrease is a small perturbation and as such may be expected to have only a small impact – if any – on competitor reactions.
Inter-island price separation	Inter-island price separation was subdued in the review period compared with previous years, when storage was high	EPOC said there is an incentive to structure offers to reduce this price separation. This would not occur in a perfectly competitive setting. BEC said offers to avoid inter-island price separation should be considered a legitimate and economically rational pricing strategy. Mercury said the new trading conduct provisions address this issue. Meridian said there were changes to the HVDC in Nov 2016 and Nov 2017 which could have impacted the observed results.	The Authority agrees with the BEC that avoiding price separation is economically rational for some generators, but we also agree with EPOC that this should not occur in a competitive market (even if the competition in the market is not perfect). Locational pricing exists for a reason – to send the right price signals for investment. Under the new trading conduct provisions avoiding price separation through offering behaviour would likely be a breach of the Code. The post implementation review of the trading conduct provisions found that price separation has been more pronounced during high hydro periods since July 2021, when the new trading conduct provisions came into force. Given the increase in price separation since the trading conduct provisions came into force it is unlikely the observed changes are entirely due to the HVDC changes in 2016 and 2017.

Trading periods with price separation in pre-dispatch but not in final	For trading periods with price separation in pre-dispatch but not in final prices, offer changes in pre-dispatch were consistent with underlying conditions. There is no evidence that any generator changed offer prices to avoid or cause price separation consistently in pre-dispatch, although some generators always have a high percentage of higher priced ('non-clearing') tranches	Meridian said some generators always have a high percentage of higher priced ('non-clearing') tranches as is to be expected to manage storage and security of supply risks over time.	We expect offers to be related to cost and underlying conditions, as set out further in sections 6 and 7 above.
Trading periods with high prices	These higher prices compared with surrounding trading periods could be explained by changes in market conditions at the time. There were no obvious signs that the changes made to offers in pre-dispatch during these trading periods were inconsistent with market conditions. However, most hydro generators still had a large percentage of offers priced at greater than the final price in these trading periods, which could	BEC stated that there are many legitimate reasons to offer capacity at higher prices. Mercury said this was a reiteration of the 'percent of offers above cost' issue and that there is no manipulation. MEUG said the Authority should clarify what percentage of offers priced above the final price as highly likely to indicate economic withholding and what the impact of this withholding would be on prices in these trading periods. It also said it would be helpful for the Authority to apply the Hidden Markov model analysis to pre 2018 price data	While this analysis is similar to the 'percent of offers above cost' indicator, this analysis was particularly looking at trading periods with high prices, to investigate whether these high spot prices could have been due to economic withholding. These trading periods were compared to surrounding trading periods and we investigated what happened in pre-dispatch for these trading periods. There are legitimate reasons to offer capacity at high prices, but it is not certain if all offers at high prices were for legitimate reasons. Some offers at high prices could be being used for economic withholding. It is not possible (due to the nature of opportunity costs) however to quantify how much quantity offered above final price would indicate economic withholding in any trading period – but

	suggest economic withholding.	and compare this to the 2018-2020 results. Meridian said it is standard practice for hydro generators to have high priced tranches to manage river chains and reservoir recharge and peaking in the short-term and to conserve storage and manage scarcity risks over longer timeframes. This is not economic withholding to increase prices and does not indicate an exercise of market power, it indicates a prudent approach to storage management.	we expect these higher priced offers to decrease when costs are lower and to vary with underlying conditions. We agree that prudent storage management is necessary, and as a result we would expect to see more generation offered at high prices when storage is low and when there is gas supply uncertainty. We would expect, however, for the percentage of higher priced offers to decrease when storage is high.
Tiwai contracts event analysis	A large change in the forward price was observed following the announcement of the contracts. Meridian's internal documentation suggests that, in negotiating with NZAS, Meridian was looking to keep the spot price from falling. If the smelter would have exited in preference to paying a market price, then the below cost contract offered by Meridian implies an efficiency cost	Several submitters thought this contract was just a one off and not a systemic issue, and that the price was not too low. Some said the deal was efficient as additional supply from Tiwai's exit would have been stranded due to transmission constraints, and Tiwai currently pays a large portion of transmission costs. Some submitters said either that this was not evidence of inefficient price discrimination or that price discrimination was not a pressing issue. Other submitters considered the contract with Tiwai effectively a subsidy from other consumers. While some submitters stated that the threat of Tiwai's exit was credible,	The Authority needs to ensure that large contracts are priced efficiently. The 'Tiwai Contracts' between Meridian Energy, Contact Energy and the New Zealand Aluminium Smelter (NZAS) highlighted the risk of inefficient outcomes (to the long-term detriment of consumers) if generators act on an incentive to subsidise extremely large load customers that could otherwise credibly exit, reduce consumption, and lower the spot price to other consumers. The risk of inefficient price discrimination arises from generators' ability and incentives. Relative to structural solutions which address generators' ability to undertake IPD, the Authority at this stage considers a Code amendment targeting generators' incentives is an appropriate solution. A Code amendment can be designed to only

		several submitters including Meridian said this was not credible and Tiwai would have been willing to pay more. Meridian stated that the price was not below their opportunity cost and that the deal is not relevant to competitive market prices or costs to consumers. It also said the deal was an extended exit deal with NZAS which had wider benefits to New Zealand, such as extending time to improve transmission out of Southland, and was well supported at the time. BEC noted that the Commerce Commission undertook a preliminary enquiry and decided not to proceed. It said it is confident there are appropriate checks and balances in place to ensure competition. It did agree however that the uncertainty over Tiwai may have discouraged investment. MEUG said that the analysis was useful but the price changes that can be linked to the Tiwai contract are modest.	target contracts with the potential for inefficient price discrimination and can be implemented relatively quickly. The Authority is consulting on a proposed Code amendment in the consultation paper 'Inefficient price discrimination in very large contracts.' The Authority has also made an urgent Code amendment to ensure consumers are protected against generators agreeing contracts with the potential for IPD prior to any enduring solution being fully consulted on and put in place.

Performance indicators

7.9 Table 6 discusses our response to points raised in submissions on the performance indicators we used in the WMR. While we have adjusted some of the analysis slightly in light of submissions, no changes have caused us to re-evaluate the observations made about the performance indicators in the WMR.

Table 6: Performance Indicators

Indicator	Our assessment in the review	What submitters said	Our updated assessment
2 percent increase in demand	There has been an increase in the average price change from a 2 percent increase in demand. This is consistent with the tighter supply situation, but also indicates that the incentive to economically withhold has increased.	Several submitters thought this was the same measure as the 2 percent decrease in demand in the SI indicator, and gave similar or identical feedback. BEC said a steeper supply curve will see an increased incentive to invest in new generation.	A 2 percent increase in demand and a 2 percent decrease are not exactly the same, although we agree they are very similar. They can however have different results in different scenarios (depending on the slope of the supply curve). Both can indicate the incentive to economically withhold generation, but larger price increases from an increase in demand could indicate incentives to invest in new generation when demand is expected to grow. The 2 percent decrease in demand in the SI was explicitly used to assess the effect that SI generators withholding generation could have had on prices over the review period, whereas the 2 percent increase in demand indicator was intended to provide a more general analysis of the effect of demand changes on pricing trends. We are looking at the overall picture provided by all of the indicators.
Spot market supply curve	Over the past few years the supply curve has become steeper, at least in the $1/MWh to $200/MWh price range. The change is less dramatic in winter when supply has generally been tighter anyway. A steeper supply curve may increase	Meridian and Mercury said a steeper supply curve indicates tight supply and tells nothing about the potential exercise of market power. Meridian also said that without being net pivotal there was no incentive to raise prices. Meridian said that generators will tend to offer to cover their commitments and physical and	While a steeper supply curve does reflect the tight supply situation it is also possible that both economic and physical withholding of generation is also contributing to the steeper supply curve. We are also concerned that steeper supply curves create an incentive to exercise market power, as the marginal generator could increase their prices by a larger amount without being

	the incentives to exercise market power.	financial risk in an uncertain environment, leading to steeper offer curves. BEC said a steeper supply curve is explainable, at least in part, by changes in the market and would also increase the incentive to invest in new generation. MEUG said the Authority should describe the behaviour it would see as withholding and an exercise of market power.	displaced by other generation, and withholding has a larger effect on the resulting price. An open question remains as to whether offering at a low price to cover commitments is consistent with competition. EPOC stated that this would not occur in a perfectly competitive market, but we do not expect perfect competition (as set out in paragraph 6.3). This question boils down to whether the resulting price reflects cost, which is what our analysis has investigated.
Marginal analysis	The percentages of time each generator is marginal are similar to previous years, and any changes during the review period are consistent with underlying conditions. However, Mercury has been marginal more often since 2018 in high-priced trading periods. This is consistent with gas supply issues (thermal is less often marginal) and dry conditions, but it could also indicate a stronger incentive and ability to exercise market power.	Both Meridian and Mercury indicated this traffic light should be green. Meridian said changes in the frequency of being marginal can be explained by supply and demand conditions. Mercury said that being marginal gives no guidance on the exercise of market power. If thermal is marginal less often other plant must be marginal more often. BEC says this may provide useful trend information over time but it is difficult to deduce anything about market power from this analysis. MEUG said the time for which a generator is gross pivotal, and the pricing offers by gross pivotal generators, are a better indication of	All of our indicators are aimed at assessing two aspects of the exercise of market power: 1. Pricing up. When a generator is marginal, it has an incentive to raise its marginal offer – at least to the level of the next highest offer in the market. 2. Economic withholding. A generator does not need to be marginal to have an incentive or the ability to exercise market power. We therefore included this indicator as part of the suite of indicators to contribute to the evidence for helping to ascertain whether generators are behaving in either of these ways. While we agree with Meridian that this indicator mainly followed underlying conditions, Mercury was (and continues to be) marginal more often

		market power and its exercise than marginal analysis.	when prices were higher. Whether this was the competitive outcome remains ambiguous. Meridian also said that generators do not have certainty when making offers in advance of real-time, so if they increase their offer price they face the risk of not being dispatched. While this is true to a certain extent, the pre-dispatch process (and historical offering behaviour) allows generators to have visibility of competitors' offers and adjust theirs accordingly up to one hour before dispatch. There is however some risk that demand or wind will change within that hour.
Actual versus predicted prices	Prices have been increasing since the Pohokura outage in 2018. Regression analysis supports a sustained upwards shift in prices since Pohokura, as do structural break tests. However, we cannot be completely sure whether this upwards shift is caused completely by underlying conditions.	Several submissions said the upward shift is explained by market conditions, such as gas supply uncertainty. Meridian and Trustpower said there were limitations of the regression analysis, such as variables being highly non-linear and correlated. Meridian also discussed how the results of a regression analysis presented in a past Authority quarterly review were in stark contrast to the regression results presented in the WMR. Carl Hansen (Capital Strategic Advisors, included as part of Meridian's submission) said that the structural breaks identified in the structural break analysis of the spot price should be dummied out of the regression.	If the dummy variable had not been significant we would conclude that it is likely that prices are following supply and demand conditions and this indicator would be green. Since the dummy is significant, it raises more uncertainty as to what is driving prices. We agree that the timing of the uplift in prices (ie, the timing of the dummy variable) supports that gas uncertainty could be a contributing factor, combined with the fact that gas uncertainty cannot be fully captured by any of the variables in the model. However, the uplift in prices could also be due to other factors not captured by the model, including the exercise of market power. The significance of the dummy variable – as Trustpower points out – could also be due to limitations of the modelling. We are not however presenting the results of the regression analysis in isolation, but rather looking at the complete picture that all of our indicators provide.

		Trustpower agreed that linear regression analysis is useful for understanding interactions in the market but did not agree that it alone could determine if the spot price was being determined in a competitive environment. MEUG said the Pohokura outage did not explain why a step change had persisted in 2019 and 2020. It questioned whether the structural break dates are linked to changes in the level of gas supply uncertainty.	Multicollinearity is always a potential problem in regression analysis but based on different configurations of the regression (some of which are included in Appendix B) we are confident that we are not missing any major explanatory variables, and the general relationships of the included variables with the spot price are robust. Once we inflation and trend adjusted the gas spot price and the carbon price, the carbon price (adjusted for stationarity) was significant – but the coefficients on the other variables in the model remained similar. While the Pohokura outage was initially resolved, it is fair to say that the incident increased awareness of the uncertainty in the gas market. However, we do not know how much of the change is due to uncertainty and how much to other factors not captured in the model. We also presented the results of the same regression analysis methodology in our June 2021 quarterly review (the one mentioned by Meridian in its submission was the June 2020 quarterly review, which used a different methodology and found autocorrelation in the residuals, so the June 2021 quarterly review used a different methodology to overcome this and provide greater flexibility in analysing time series data. The June 2020 quarterly review also only included data up to 29 February 2020). At that time we included the generation HHI as a measure of competition, but found that the storage effect dominated any market

			concentration effect. In the WMR we therefore decided this variable was not an appropriate variable to include in the regression analysis. We also updated the storage variable to be the difference from mean storage rather than absolute storage in GWh. We also only used data back to 1 October 2015 in the quarterly review as we used a different source for the gas spot price (for the WMR we used data back to 1 January 2014). All of these changes resulted in a slightly different model – and therefore different results – to those presented in the June 2021 quarterly review. We re-ran the regression analysis substituting the gas VWAP with the 90th percentile, and found that this increased the dummy variable slightly to $42/MWh. Results of this analysis are in appendix B. We also included dummy variables for the structural breaks as identified in the structural break analysis (using the breaks identified in the level structural changes analysis, ie, one at 11 October 2019 and one at 21 October 2020), as suggested by Carl Hansen. This analysis supports our initial regression results that there was a sustained upwards shift in prices since the Pohokura outage, and that we cannot be completely sure whether this upwards shift is caused completely by underlying conditions.

Forward prices	The forward price was pricing in certain scarcity for some of 2021 but, overall, is unbiased.	Meridian and Mercury thought the traffic light should be green. BEC agreed that forward pricing for Q1-3 2022 included pricing for fuel scarcity as gas maintenance works continued into these quarters. MEUG said this conclusion is not consistent with paragraph 2.9 in the WMR, and that spot prices have been higher than predicted by forward prices since 2018.	The primary reason this was not green is because forward prices indicated that scarcity was being priced in as certain. We found it surprising that scarcity was priced as certain given there is always a chance of high inflows leading to low prices. Paragraph 2.9 in the WMR is based on analysis published in April 2021 which compared future prices against actual spot prices up until the end of Q1 2021. However, this indicator is based on 2021 forward prices for 2022, which were much higher than prices up to Q1 2021. We agree with BEC that gas supply uncertainty may have had some impact on forward prices at that time, as there was ongoing uncertainty. However, increasing certainty was signalled for the second half of 2022,[32] so the high forward prices predicted for the September 2022 quarter back in June last year still seem high. Additionally, gas supply uncertainty should have a smaller impact on forward prices under normal hydrological circumstances (ie, if hydro scarcity was not forecast as a certainty).
Cost to income ratio	Concept's analysis does not opine on what profits should be, only whether they have changed and their proximate	Mercury said it is not surprising for some generators with low-cost fuels to make higher profits during periods of high prices and that there is no	We did not look at this indicator in isolation. Rather, we assessed the overall picture provided by all of our indicators. The change in Meridian's EBITDAF is indicative – when combined with the

[32] In May 2021 Genesis and Methanex signed a deal to supply winter gas to Huntly (included for 2022 and 2023). The Gas Industry Company put out its gas market settings consultation paper in May 2021 which said "The tight supply conditions being experienced this year appear likely to continue into 2022. There is a possibility this will be avoided if remedial work at the Pohokura field can be undertaken over the coming summer.". https://www.gasindustry.co.nz/assets/DMSDocumentsOld/7263~Gas-Market-Settings-Investigation-Consultation-Paper-May-2021-v2.pdf. All remedial works at gas fields were signalled well in advance, and most to occur in early 2022.

	causes. For most firms, earnings did not change markedly between FY 2018 and FY 2020. Meridian was the exception with an increase in earnings.	evidence of barriers to entry for investment. Meridian said this indicator should not be included. The limited time period leads to misleading conclusions. A positive change does not mean Meridian has exercised market power (but could be due to factors outside of the generator's control, such as high prices associated with gas supply issues) and there were no findings of supernormal or sustained profits. The independent retailers and MEUG said the analysis focussed on the change in profits (over a short period of time) following the Pohokura outage and did not consider if profits are supernormal or excessive during the review period or prior to 2018. Trustpower said profitability needs to be considered over an appropriate timeframe given the nature of underlying investments. Meridian's increase in EBITDAF over the short period considered by the review is not sufficient to draw any conclusive views. Paua to the People argued that the recent profitability of gentailers	other indicators – of a change during the review period compared to previous years. The short timeframe is not a limitation of the analysis since we have transparency around the source of the profits. Concept found that Meridian appears to have benefited from a combination of moving its generation volumes away from spot market sales and into higher value sale channels (e.g. residential customer sales) and increased market prices in some sale channels (e.g. C&I customer sales).[33]

[33] See https://www.ea.govt.nz/assets/dms-assets/29/Concept-Report_-Analysis-of-generator-retailer-financial-data-v2.pdf.

		indicates they can command spot prices in excess of their costs.	
Investment	The pipeline of build-ready investment projects has become very thin. There has also been uncertainty of various types in the investment environment, which has likely affected investment decisions. Furthermore, the relatively thin pipeline for new supply may be weakening the incentive on existing players to commit new investment in a timely manner.	Some submitters agreed that there was a thin pipeline of new investment, indicating there were barriers to entry while other submitters thought there was an appropriate amount of new investment and no barriers to entry. For example, Contact said all three of the new generation plants built during the review period were built by new entrants, indicating no barriers to new entrants. Several submissions discussed potential barriers to entry, such as the lack of access to firming generation (or flexible load contracts) for new wind generation, falling capital costs (cheaper to invest in the future), and increased uncertainty due to Tiwai and the NZ Battery Project. Paua to the People questioned the assumption that high spot prices and futures prices lead to investment in generation as this cannot be substantiated given we have had very high prices for some time and an under investment in new generation. It said there has been limited investment in new generation as gentailers work to constrain supply and ensure high-cost	The potential barriers to entry identified by various submitters have been considered as part of the further work on investment undertaken by Concept. This work found that there has been a material acceleration in generation development since the WMR was published. However, despite the volume of committed and actively pursued projects, forward contract prices remain well above the estimated cost of new supply out to 2025. Potential impediments include RMA requirements, overseas investment consenting arrangements, securing offtake arrangements, connection study requirements, and cost pressures. These are discussed in our companion paper.

		thermal generation is required as much as possible. Energy Link said that the current market does not provide incentives to switch from fossil fuels to electricity (e.g. for process heat) as increased carbon prices also increase electricity prices. Some submitters also said the Authority should also consider barriers to entry of large load, which is important for the decarbonisation of the whole economy. Overall, most submitters supported further work on potential barriers to entry.	

8 The new trading conduct provisions appear to be having an impact

8.1 The recent post implementation review of the trading conduct provisions observed evidence that suggests competitive outcomes may have improved since the WMR period. Prices have tended to better reflect underlying conditions since the new provisions came into effect. Price separation has become more pronounced and there has been an increase in the frequency of very low prices. The percentage of high-priced offers has decreased, and offer prices appear to be reflecting underlying conditions and economic costs more closely. Of 22 issues identified for further analysis under the Authority's proactive regular monitoring, only three have been passed to the Compliance team and two of these have resulted in no breach being found (one remains in the fact-finding stage).

8.2 However, as with the WMR findings, this conclusion is not definitive, and average prices have remained high since the WMR period. Additionally, forward prices remain high – above the estimated cost of new supply out to 2025. Despite the volume of committed and actively pursued new renewable generation projects in the pipeline, this suggests that uneconomic thermal generation may remain in operation until at least (and probably beyond) 2025. This suggests that prices may be above the long-run cost of new supply for many years yet.

8.3 Additionally, the structure of the market in the future implied by the pipeline is one that remains highly concentrated. This suggests trading conduct provisions will continue to remain important for mitigating the exercise of market power. However, it remains unclear as to whether the *current* trading conduct provisions will be effective once we reach 100% renewable electricity. Opportunity cost measurement under 100% renewable electricity will likely become even more fraught than it is already, so the monitoring we currently undertake assessing offers against costs may need to be reconfigured. Management of hydro storage will need to change as it will need to be kept in reserve for fluctuations in intermittent generation such as wind and solar. New fuels such as hydrogen and biofuels may supply back-up plant and flexible demand may have a more significant role in spot price formation. We may therefore be able to form expectations based on these factors that would allow us to monitor outcomes under the trading conduct provisions as they currently stand. As with the analysis presented in this review, expectations involve judgements and this will be no different in the future.

Appendix A Including unoffered capacity in the conduct indicators

A.1 Table 7 shows the results of our analysis including unoffered capacity for the hydro generators. We followed Meridian's analysis and put the unoffered capacity (where not indicated as an outage on POCP) to $301/MWh. The results show an increase in percentages for all hydro generators, but Mercury (Waikato) and Meridian (Waitaki) still have a higher percentage of higher-priced offers when hydro storage is higher, compared to Genesis (Tekapo) and Contact (Clutha).

Table 7: Updated percentages when include unoffered capacity – review period (2019 to June 2021)

Indicator	Storage level	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Tekapo)	Contact (Clutha)
Percent of offers above $300/MWh	**Low hydro storage (less than 80% of mean)**	61	41	36	41
	High hydro storage (greater than or equal to 100% of mean)	53	31	9	12
Percent of offers greater than SRMCs	**Low hydro storage (less than 80% of mean)**	45	42	40	42
	High hydro storage (greater than or equal to 100% of mean)	40	33	9	20
Percent of offers greater than DOASA water value	**Low hydro storage (less than 80% of mean)**	71	53	46	46
	High hydro storage (greater than or equal to 100% of mean)	64	40	10	31

Appendix B Updates of dynamic regression analysis of spot price drivers

B.1 In the WMR we included a dynamic regression analysis of spot price drivers. In response to feedback we ran the analysis again with some changes. Besides the change of explanatory variables, the data and model were exactly the same. See Appendix A in the WMR information paper for more details. The results from the model published in the WMR information paper are in Table 8, which is the same as Table 26 in Appendix A of the WMR information paper.

Table 8: Results from the regression as in the review paper

	Coefficients	p-values	Significant
AR1	0.6908	0	Y
AR2	-0.0222	0.3	N
AR3	0.0492	0.04	Y, at 5%
AR4	0.0788	0	Y
AR5	0.0422	0.03	Y, at 5%
Intercept	67.1522	0	Y
Adjusted Storage	-0.0613	0	Y
Diff(demand)	0.6843	0	Y
Wind generation	-6.2694	0	Y
Gas price	3.0827	0	Y
Dummy	38.7416	0	Y

B.2 The first new iteration of the regression analysis used an estimate of the marginal gas price instead of the average gas price (VWAP). This was done by calculating the price at which the 90^{th} percentile of gas was traded at.

Table 9: Results from the regression using 90th percentile

	Coefficients	p-values	Significant
AR1	0.6971	0	Y
AR2	-0.0274	0.2	N
AR3	0.0472	0.04	Y, at 5%
AR4	0.0829	0	Y
AR5	0.0445	0.02	Y, at 5%
Intercept	73.208	0	Y
Adjusted Storage	-0.0607	0	Y
Diff(demand)	0.6824	0	Y
Wind generation	-6.3382	0	Y

Marginal Gas price	1.8451	0	Y
Dummy	43.7009	0	Y

B.3 The second iteration of the regression analysis added in the standard deviation of the gas price (weighted by volume traded) in an attempt to capture uncertainty in the gas market.

Table 10: Results from the regression including the standard deviation

	Coefficients	**p-values**	**Significant**
AR1	0.6913	0	Y
AR2	-0.0239	0.3	N
AR3	0.0482	0.04	Y, at 5%
AR4	0.0825	0	Y
AR5	0.0410	0.03	Y, at 5%
Intercept	67.9520	0	Y
Adjusted Storage	-0.0614	0	Y
Diff(demand)	0.6837	0	Y
Wind generation	-6.3241	0	Y
Gas price	2.8722	0	Y
Sd of Gas price	1.6080	.01	Y, at 5%
Dummy	38.6307	0	Y

B.4 The third iteration of the regression analysis added two additional dummy variables, as identified in the structural break analysis.

Table 11: Results from the regression including two additional dummy variables

	Coefficients	**p-values**	**Significant**
AR1	0.6855	0	Y
AR2	-0.0246	0.3	N
AR3	0.0468	0.04	Y, at 5%
AR4	0.0771	0	Y
AR5	0.0349	0.07	Y, at 5%
Intercept	67.0118	0	Y
Adjusted Storage	-0.05632	0	Y
Diff(demand)	0.6851	0	Y
Wind generation	-6.265	0	Y
Gas price	3.0392	0	Y

Dummy 1	42.4738	0	Y
Dummy 2	-20.8143	0.02	Y, at 5%
Dummy 3	39.5375	0	Y

B.5 The fourth iteration of the regression analysis changed the inflation adjustment of the electricity spot price to use the PPI over all industries (rather than the electricity component of the PPI), and also inflation adjusted the gas spot price and the carbon price (and also trend adjusted these series as we did with the electricity spot price). This resulted in the carbon price (first differenced to make it stationary) becoming significant at the 5 percent level.

Table 12: Results from the regression changing the inflation adjustment for the electricity and gas spot prices, and adding the inflation and trend adjusted carbon price

	Coefficients	p-values	Significant
AR1	0.6825	0	Y
AR2	-0.0330	0.2	N
AR3	0.0715	0	Y, at 5%
AR4	0.0781	0	Y
AR5	0.0551	0	Y, at 5%
Intercept	72.11	0	Y
Adjusted Storage	-0.0643	0	Y
Diff(demand)	0.5890	0	Y
Wind generation	-6.7367	0	Y
Inflation and trend adjusted Gas price	3.4301	0	Y
Dummy	40.8372	0	Y
Diff(Inflation and trend adjusted Carbon price)	2.1028	0	Y, at 5%

Glossary of abbreviations and terms

ACCC	Australian Competition and Consumer Commission
ASX	Australian Securities Exchange
Authority	Electricity Authority
BEC	BusinessNZ Energy Council
Code	Electricity Industry Participation Code 2010
Contact	Contact Energy Limited (CTCT)
DOASA	model of system-wide scheduling
E3P	Unit 5 at Huntly
EBITDAF	earnings before interest, tax, depreciation, amortisation and fair value adjustments
Economic withholding	offering some quantity at higher prices with the intention that it not be dispatched, thus reducing supply and increasing the spot price
EPOC	Electric Power Optimisation Centre
Genesis	Genesis Energy Limited (GENE)
Gross pivotal	If there are any trading periods where the generation from a trader is needed to meet demand, then this trader is gross pivotal in those trading periods
GJ	gigajoule
GSAs	gas supply agreements
GW	gigawatt
GWh	gigawatt hour
HHI	Herfindahl-Hirschman Index for assessing seller concentration
HLY	Huntly
HVDC	high voltage direct current connection between the South Island and North Island (or Cook Strait Cable)
Lerner Index	index of marginal price above cost
LRMC	long-run marginal cost
MDAG	Market Development Advisory Group
Mercury	Mercury NZ Limited (MRPL)
Meridian	Meridian Energy Limited (MERI)
MEUG	Major Electricity Users Group
MW	megawatt
MWh	megawatt hour
NI	North Island
NZAS	New Zealand Aluminium Smelters Limited
OCGT	open cycle gas turbine
OTCs	Over-the-counter contracts
Pohokura	the Pohokura gas field
POCP	Planned Outage Coordination Process https://customerportal.transpower.co.nz/pocp
PPA	power purchase agreement
PPI	producer price index
PJ	petajoule
QWOP	quantity weighted offer price
RMA	Resource Management Act
SCP	structure, conduct and performance
SI	South Island
SPD	scheduling, pricing and dispatch

SRMC	short-run marginal cost
Tiwai	the aluminium smelter at Tiwai Point
Tiwai contracts	the Contract for Differences contracts between Meridian and NZAS, and between Contact and Meridian, relating to the supply of power to the Tiwai Point smelter for 2021 to 2024
TJ	terajoule
TCC	Taranaki Combined Cycle
UTS	Undesirable trading situation
VI	vertical integration: in the electricity market this refers to where a firm is both a generator and a retailer
vSPD	vectorised scheduling, pricing and dispatch — the vSPD model is a precise replica of scheduling, pricing and dispatch
VWAPs	value weighted average prices
WMR	Market Monitoring Review of structure, conduct and performance in the wholesale electricity market – Information paper

A detailed glossary is available at www.ea.govt.nz/glossary