Meridian submission

Review of competition in the wholesale market

22 December 2021

This submission by Meridian Energy Limited (**Meridian**) responds to two papers published by the Electricity Authority (**Authority**) under its review of competition in the wholesale market from January 2019 to June 2021:

- *Market Monitoring Review of Structure Conduct and Performance in the Wholesale Electricity Market* (**the information paper**); and
- *Inefficient Price Discrimination in the Wholesale Electricity Market* (**the issues and options paper**).

The following expert reports are appended in support of this submission:

- Axiom *Economic Review of the Electricity Authority's Analysis of Spot Prices*
- Carl Hansen *Report on the Electricity Authority's competition and price discrimination papers of 27 October 2021*
- Grant Read *Interpreting Hydro Offers in the NZEM: Reflections on the Electricity Authority's October 2021 Market Monitoring Review*
- Sapere Research Group:
  - *Efficient price discrimination in the wholesale electricity market*
  - *Regulatory uncertainty and long-term harm to consumers*
  - *Vertical integration and consumer benefit in the New Zealand electricity sector*.

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Nothing in this submission is confidential.

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Executive Summary

Meridian welcomes ongoing monitoring of the wholesale market by the Authority. Such monitoring provides participants and consumers with confidence that the market is operating as intended for the long-term benefit of consumers.

The Authority's information paper finds that wholesale prices over the review period generally reflected underlying supply and demand conditions. The information paper focuses on a component of the uplift in prices that may not be fully explained by its chosen regression analysis and speculates about whether that component can be attributed to the exercise of market power. The issues paper specifically explores the contract between Meridian and the New Zealand Aluminium Smelter (NZAS) and asks whether inefficient price discrimination has occurred, and if so, what regulatory options might be considered in response.

The current review is the tenth review the Authority has carried out since the Pohokura gas production outages in Spring 2018. The Authority has also recently published an independent review of the 2021 dry year, overlapping with the January to June 2021 portion of the review period. There has accordingly been no shortage of electricity market scrutiny since Spring 2018.

All the empirical analysis carried out by the Authority indicates that the higher prices during the review period reflect supply and demand conditions. During the review period the electricity market experienced higher demand, significant continuing uncertainty surrounding gas supply, chronic uncertainty over the future of the Tiwai Point aluminium smelter, high gas spot prices, drier conditions in hydro catchments with periods of quite low storage, and significantly increased emissions costs for thermal and geothermal generators.

It is important to note that households have been largely insulated from higher wholesale prices because of fixed price residential contracts and retailers' longer-term view of pricing that rides through short-term volatility. According to household price data from the Ministry of Business Innovation and Employment, the real residential cost per unit of electricity has fallen in every year of the review period.

Meridian agrees with the Authority's overall conclusion, confirmed by its two peer reviewers: "evidence of the exercise of market power was not found."

The preliminary concerns identified by the Authority in relation to offer prices are readily resolved when the effect of gas market uncertainty on hydro storage management and the impact of hydro offer prices on long-term security of supply are taken into account. By questioning whether hydro offers could have been lower the Authority seems to assume a "free lunch" whereby hydro generation can be increased through lower offer prices without impacting lake levels, security of supply, and prices in future. As we show in this submission, if Meridian offered its hydro generation at the lower levels implicitly suggested by the Authority's analysis, the risk of shortage would be extreme. Put simply, the lights would go out more frequently. Meridian does not consider this to be in the interests of electricity consumers – the costs of energy shortage are severe, as are the political consequences for generators and regulators. Current risk settings as reflected in the hydro offers seen over the last few years have in our view delivered an appropriate level of security of supply.

The Authority's analysis of offer prices does not recognise generation portfolios. For example, the analysis considers only Meridian's Waitaki generation rather than looking at offers across Meridian's portfolio, including Manapōuri generation. Looking at *all* offers rather than only selected offers would produce different insights for the Authority's analysis of generator conduct.

The Authority's analysis also only considers offers actually made and does not recognise that at times some generators simply do not offer all available generation (which is economically and practically equivalent to offering some generation at a very high or infinite price). This can be contrasted with Meridian, which always offers all available generation while pricing some generation capacity at high prices so it is not expected to be dispatched (unless there is an unexpected capacity shortage or system stress event) and therefore hydro resources are stored for the future. To obtain a proper picture of the functioning of the wholesale market it is important that all offer decisions (including decisions not to offer into the wholesale market) are considered. In effect, the Authority's offer price analysis implicitly penalises Meridian for choosing to make generation capacity available for exceptional circumstances that would otherwise be withheld for storage management reasons.

Higher wholesale prices are a strong incentive to invest in new generation and the entry of new generation is the primary mechanism to soften wholesale prices. A wave of investment is now occurring from a diverse range of businesses, including several new entrants. On this critical dynamic efficiency measure the wholesale market is performing well and

Meridian's expectation is therefore that wholesale prices will converge over time on the cost of new entrant generation. Construction of new generation does not occur overnight. The uplift in wholesale prices due to gas supply issues of the last few years was unforeseen and comes after many years of zero demand growth. There have also been several legitimate sources of investment uncertainty. However, investments are nonetheless now occurring at pace and scale. By Meridian's estimate over $2 billion of investments have been completed in the past year, or are planned, or are under construction. Once completed this generation will be equivalent to around 8% of current demand. Examples include:

- Meridian's Harapaki wind farm;
- Meridian's Ruakaka Energy Park (solar and battery);
- Contact's Tauhara geothermal plant;
- Mercury's Turitea wind farm;
- Tilt's Waipipi wind farm;
- Top Energy's Ngawha geothermal expansion;
- Lodestone Energy's five solar farms in Northland, Coromandel, and Bay of Plenty;
- Christchurch International Airport's recently announced Kōwhai Park energy precinct and initial $100 million investment commitment from Solar Bay; and
- Hiringa's investment with Balance in a 24MW wind farm.

Another important piece of context is that the Authority introduced new trading conduct rules in June 2021, which require all offers to be consistent with offers that the generator would make if no generator could exercise significant market power. Meridian anticipates that enforcement of these rules by the Authority will be sufficient to address any exercise of market power that it has concerns about in the future.

Meridian is surprised that the Authority's primary focus in its papers is not on the performance of the market but on a single hedge transaction agreed between Meridian and the New Zealand Aluminium Smelter (NZAS). After 50 years of smelting operations in New Zealand, NZAS agreed to postpone its planned exit from the New Zealand market by just over 3 years from August 2021 to December 2024. The Authority speculates that NZAS does not sufficiently value the electricity it consumes and that in a narrow electricity market-sense there may be higher-value uses. The Authority is clear that the key criterion of value and measure of inefficiency is not the actual price in the contract but rather is NZAS' willingness-to-pay relative to alternative potential users of the electricity. NZAS' willingness-to-pay is inherently unmeasurable and only known by the owners of NZAS. The Authority has mistaken statements made by NZAS as indicative of a low willingness-to-pay when in reality those statements were more likely part of a bargaining strategy. NZAS' willingness-to-pay almost certainty takes into account long-term expectations of aluminium prices rather than a snapshot in time. The rise in world aluminium prices over the last year or so implies that the smelter's willingness to pay is much higher (in the order of $140/MWh based on August 2021 Aluminium prices), and this would lay to rest any concerns about inefficient price discrimination.

Meridian does not consider the NZAS contract to be an example of inefficient price discrimination. The Authority's analysis that leads it to suggest the opposite is flawed and makes several incorrect assumptions regarding Meridian's opportunity cost, and the willingness to pay of NZAS. Meridian will demonstrate in this submission that:

- Meridian did *not* sell a hedge to NZAS below its opportunity cost;
- household electricity prices would not likely have been significantly affected by a smelter exit;
- the Authority focuses supposed efficiency gains that would result from short term disequilibrium in the wholesale market due to a demand side shock – it would be unusual for a regulator to take such a short term view;
- an extended exit deal with NZAS had wider benefits to New Zealand and was widely supported at the time (including by the Government and the Authority itself);
- NZAS would likely have stayed even if an agreement was not reached in January 2021;
- the Authority's analysis is based on untestable assumptions about consumer willingness to pay rather than any real-world evidence; and
- the intervention options contemplated exceed the Authority's mandate and risk significant consumer detriment without addressing any proven problem.

Meridian's objective in the negotiations with NZAS was to facilitate a managed exit of the smelter in a way that supported both our commercial interests and importantly the interests of the Southland community and the broader energy system. We were transparent with the market about our intentions at every stage including keeping key Government agencies well briefed. Importantly, this was an exit deal for four years and not a perpetual extension of the smelter operation. The contract bought New Zealand time to improve transmission out of Southland and develop alternative uses for the hydro generation that would otherwise have been stranded and of limited value to Meridian in the event of a smelter exit. There has for example been strong commercial interest in the Southern Green Hydrogen project to construct the world's first large scale green hydrogen production facility. We believe we can make hydrogen production economic now through innovative contracting with flexible demand response. The international registration of interest process closed in September with strong interest from large credible international firms. They have confirmed that the hydrogen opportunity in Aotearoa is world leading and there will be strong competition from them to be part of this project as we move to short list parties for the request for proposals and commercial negotiations. We are targeting a final investment decision ahead of 2024. Several other potential uses related to long term decarbonisation of the New Zealand economy are also being considered. The point being that in 2025 there will be stronger competition for the energy currently supplied to the smelter and we expect that competition will mitigate any concern the Authority might have about inefficient allocation of electricity.

In the absence of evidence of inefficient price discrimination, or of significant risk of it, the intervention options contemplated by the Authority would not survive any rigorous cost benefit assessment to the extent that they impose material costs on consumers. In particular, the interventions would all appear to involve significant limitations on the free trading of risk, thus increasing the cost of doing business, weakening investment signals, and creating uncertainty regarding the rules that will apply to the trading of risk which underpins investment. Such interventions will ultimately increase the cost of electricity for consumers. The Authority should instead focus on the widely acknowledged uncertainty regarding gas supply and consider options to reduce that uncertainty for market participants.

Meridian agrees there is no evidence that market power has been exercised

Wholesale prices are explained by underlying supply and demand conditions

Meridian agrees with the Authority that since the first Pohokura outage in 2018, the spot market has experienced higher prices, higher demand, continuing uncertainty surrounding gas supply, and high gas spot prices. As noted by the Authority, the climate has also generally been drier, with periods of quite low storage, and the cost of carbon emissions has increased significantly.

The Authority's statistical regression models "provide evidence to support the hypothesis that spot prices are determined by the balance of supply and demand."[1] However, the Authority indicates that some portion of the upwards shift in prices is not explained by the Authority's statistical analysis and must be attributable to some other unexplained variable. The Authority speculates that this portion of the upward shift in spot prices could be due to:

- limitations of the model (no model is likely to perfectly capture all variables or perfectly describe the complex relationships between variables);
- the uncertainty surrounding gas supply from Pohokura and other fields (above that reflected in the gas spot price); or
- some other reason, such as the exercise of market power.

The Authority acknowledges that it is not possible to conclude the reason/s for the statistically unexplained component of the price increase because even with all the data available to the Authority it is difficult to account perfectly for all underlying conditions. The wholesale electricity market is a complex, real-time interaction of independent participants, each with imperfect information.

This review is the tenth market performance review or insight published by the Authority since the Market performance review of Spring 2018. In all ten reviews over the course of three years the Authority has not found any evidence that the exercise of market power has contributed to the sustained uplift in wholesale prices.[2]

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[1] *Information paper* paragraphs A.34 and A.35.

[2] Indeed, previous reviews by the Authority have found "evidence to support the hypothesis that spot prices are determined by the balance of supply and demand and that these effects dominate any effects due to market concentration. Note that price being determined by underlying demand and

We agree with the peer reviews: there is no evidence market power has been exercised

The Authority's papers were peer reviewed by Pat Duignan and Concept Consulting. Meridian generally agrees with the comments from both peer reviewers:

> "The regression analysis is technically very thorough and provides robust evidence of a structural change in the influences on spot prices, dating from the Pohokura outage. The regression analysis cannot however pin down the extent to which the change reflects uncertainty regarding medium term gas supplies, over and above the direct effect on spot gas prices, versus the exercise of market power... As the paper concludes… definitive evidence of the exercise of market power was not found."[3]
>
> "The Authority's overall conclusion is that it did not find definitive evidence of an exercise of market power… We think this overall conclusion is reasonable in light of the available evidence."[4]

The Authority's analysis of the uplift in price through a dummy variable considers the timing of the uplift and factors such as Ahuroa storage, which by the Authority's account "lends support to the proposition that the dummy variable is, at least to some extent, picking up an effect due to increased uncertainty surrounding gas supply from Pohokura and other fields." An accurate summary of the information paper would therefore be that the Authority's analysis cannot be conclusive regarding the causes of the statistically unexplained portion of price uplift, but there are good indications that it is related to gas supply uncertainty.

There has been significant gas market uncertainty, not just a change in gas prices

Meridian does not attribute the statistically unexplained structural uplift in prices to the exercise of market power. Since Spring 2018, hydro generators like Meridian have been managing scarce hydro resources in light of increased uncertainty about thermal generation. The prices at which we have observed thermal commitment have changed – as noted in the Authority's analysis of gas spot prices, gas supply agreements, and estimates of the short

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supply indicates effective competition. The model confirms what we qualitatively observe about the spot market: that high spot prices tend to coincide with low wind, low storage, high gas spot prices and other gas sector disruptions, and high demand." https://www.ea.govt.nz/assets/dms-assets/27/27142Quarterly-Review-July-2020.pdf page 25.

[3] https://www.ea.govt.nz/assets/dms-assets/29/Munro-Duignan-Review-Letter-for-Information-Paper-v2.pdf

[4] https://www.ea.govt.nz/assets/dms-assets/29/Concept-Review-Letter-for-Information-Paper-v3.pdf

run marginal costs of thermal generation. However, in addition to issues associated with higher gas *prices*, we have commonly observed a lack of thermal generation commitment, indicating a lack of fuel availability and deliverability (or unwillingness to contract gas) seemingly irrespective of price.

We have far from perfect information about the gas industry and are not privy to the information the Authority has seen in this review. Other hydro generators are likely in a similar position. The uncertainty has a significant impact, and this has not been properly accounted for by the Authority. Meridian's offers respond to what we observe in the market and the extent of uncertainty regarding the behaviour of thermal generation. Meridian's primary objective is always to prudently manage storage given the full range of uncertain future inflows and a series of assumptions about the behaviour of other generators. Meridian has always sought better thermal fuel disclosure to help us understand the behaviour of thermal generation and better reflect gas availability and deliverability issues in the way we value and manage our hydro storage; however, to date, not much has been forthcoming other than some voluntary disclosure of planned gas production outages.

The Authority does not appear to consider the possibility of economic withholding by thermal generators when considering the lack of thermal commitment over the review period. The Authority has only considered gas prices, not availability and deliverability, nor uncertainty, and nor the resulting reduction in thermal commitment. The issues with the gas market and resulting changes in thermal generation offers seem largely to be taken as a given. Instead, the Authority focuses on the way hydro generators have responded to the issues in the gas market and moves directly to consider whether hydro generators are engaging in economic withholding. In so doing, the Authority omits adequate consideration of imperatives relating to the prudent management of hydro storage.

The Authority has made no attempt to understand the impact of gas market uncertainty on hydro storage management and security of supply

The Authority acknowledges that "any generator with storage makes an inter-temporal trade-off between generating or storing, and that decision depends on their (unobservable) expectations of future outcomes" and that "it is difficult to distinguish between withholding to maintain sufficient fuel for future generation, and withholding to increase the price".[5] While the Authority welcomes feedback on this, it has not itself attempted to assess whether hydro

[5] *Questions and Answers on the Electricity Authority's Wholesale Market Review* 7 December 2021.

offers have resulted in prudent storage management and responded appropriately to increased thermal fuel scarcity and uncertainty. Any suggestion that hydro generators could sustainably have offered more generation at lower prices across the review period, is in effect a suggestion that consumers should accept an increased risk of shortage and the potentially severe economic and political consequences that shortage would entail. The Authority seems to make this suggestion without attempting to quantify that increased risk. We doubt this would lead to better outcomes for consumers.

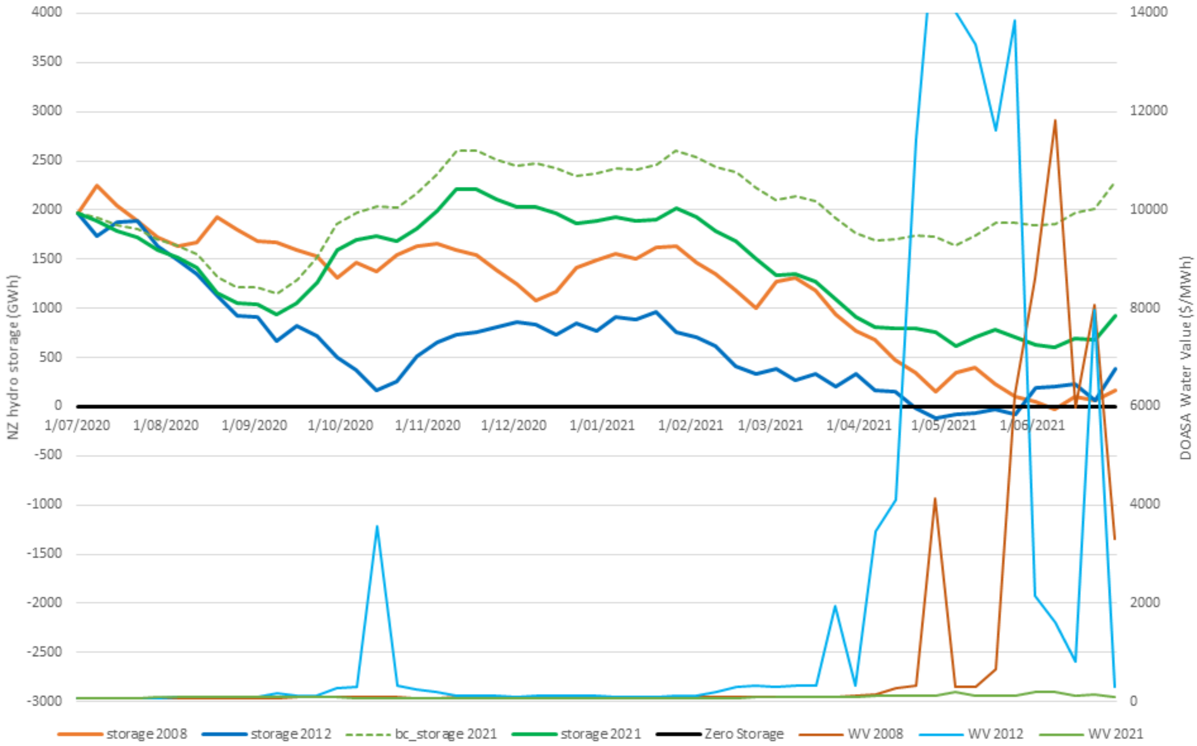
There is no "free lunch" when managing scarce hydro resources; if hydro generators use more water in the short term at lower prices the risk of shortage increases as does the risk of much higher prices in the longer term. Grant Read explores this issue more thoroughly in his attached report.

As an example, Meridian has modelled using vSPD the storage outcomes that would have resulted in 2021 if hydro storage was offered at the water values produced by the DOASA model which the Authority cites throughout the information paper. The dashed green line of actual 2021 storage outcomes is left as a comparator.

We also modelled what 2021 would have looked like using DOASA water values but with a drier inflow sequence (using 2008 and 2012 inflows). In short, DOASA water values do not rise early enough to dispatch enough offered thermal generation to prudently conserve hydro storage, leading to:

- Storage approaching close to the Official Conservation Campaign start trigger in 2021 – an extraordinary outcome as 2021 was drier than average, but not very dry.
- If 2021 had been drier and more like the hydrology seen in 2008 and 2012 then using DOASA water values would have meant New Zealand would have run out of controlled hydro storage and there would not have been enough total thermal offers to avoid energy shortage, therefore load shedding would have been likely over significant periods of time. Figure 1 below shows this happening from late April applying the 2012 pattern of inflows and from some time in June using the 2008 pattern of inflows. This shortage is reflected in the *very* high DOASA lookup water values. If hydro generators had behaved in this way, they would undoubtedly have faced considerable backlash from stakeholders, regulators, and politicians.

Figure 1: NZ hydro storage outcomes using DOASA water value lookups for 2008, 2012, and 2021 inflows solved using vSPD



Any commentary from the Authority suggesting hydro offers could have been different is a suggestion that storage management should have been conducted differently. The Authority is entitled to suggest this would be a better outcome for New Zealand provided it has fully understood the outcome it is promoting, but it has stopped short and considered offer prices in isolation from storage. In other words, the Authority is assuming a “free lunch” and that hydro generation can be increased without impacting lake levels. The Authority has not in any of its extensive analysis described any counterfactual storage scenarios nor the implications for security of supply.

What the Authority frames as a conversation about potential economic withholding is in fact a conversation about prudent storage management and the level of risk aversion that is to be expected in this market given gas supply uncertainty. If the Authority wants to pass judgement (or be prescriptive) about offer values and override participants’ commercial judgements, then the corollary is that the Authority must take responsibility for outcomes in terms of storage and security of supply. Previous regulatory interventions have pushed hydro generators to be more risk averse[6] and the Authority now seems to be signalling a regulatory desire to move in the opposite direction, without considering if the storage

[6] The 2009 Ministerial Review of Electricity Market Performance and Code changes to enable official conservation campaigns, the customer compensation scheme, stress testing, and scarcity pricing.

implications would actually be better for the country. This is particularly unhelpful because the Authority has not approached the question of storage management directly but instead chosen to view a failure to generate to DOASA water values (or some other flawed estimate of short run costs) as potential economic withholding for revenue purposes without acknowledging or considering the inevitable storage implications of that action in any way.

Meridian shared its modelled optimal generation volumes with the Authority prior to publication of the review papers. The very close correlation between actual generation and modelled optimal volumes is direct evidence that the supposedly unexplained uplift in prices is (at least for Meridian's part) *not* attributable to the exercise of market power but rather the offers that were required to deliver prudent storage management in the face of increased uncertainty about gas generation and limited gas flexibility. Meridian's storage management has evolved over more than two decades and has been tested through a large range of market and weather-based events. We consider Meridian's risk appetite to be prudent, without being unduly conservative, both from our own perspective and from the broader perspective of playing our part to ensure security of supply for Aotearoa.

The Authority commissioned an independent review of 2021 by Martin Jenkins (overlapping with the last six months of the Authority's own wholesale market review). The independent review of 2021 found:[7]

> "The system worked as intended. The 2021 dry year demonstrated the resilience of New Zealand's electricity market mechanisms, even under the added stress of further environmental factors such as gas supply pressures. Water was preserved appropriately through use of alternative generation mechanisms, and the country retained an appropriate hydro supply buffer to take forward to 2022."

We encourage the Authority to consider the independent review findings alongside its own analysis. If storage management was indeed prudent then it is difficult to understand how the Authority could question hydro generators' use of offer pricing to conserve water over the review period. Any suggestion that those offers could have been an exercise of market power to increase revenue is clearly not supported by the evidence.

[7] https://www.ea.govt.nz/assets/dms-assets/29/Consultation-2021-Dry-Year-event-review-v2.pdf.

Analysis of long term market dynamics would be more meaningful than static analysis of prices and short run costs

As set out in the attached report from Axiom Economics, few insights into the state of competition can be gleaned from comparing spot prices with estimates of short run costs. That is because it is impossible to produce objectively robust estimates of short run costs, given the complexities involved in measuring opportunity costs in New Zealand's hydro-centric system. Despite this, much of the analysis in the information paper entails precisely this kind of assessment. As Axiom explains, those assessments are of little or no probative value. A better way to gauge the state of competition in the wholesale market is to consider long-term dynamics through a lens of workable competition (as has been the case in previous examinations of the wholesale market by the Government and the Commerce Commission).

Stepping back from the Authority's papers, Meridian considers the strongest indicator of a healthy and competitive wholesale market to be investment in new generation. New entry should ensure that over time spot prices do not for long exceed the cost of new entrant generation. In this regard, there has been an enormous recent increase in connection requests, surging development interest in solar farms and around $2 billion of investments either recently completed, committed, or under construction. Investment is being undertaken both by incumbent generators and by new entrants, for example:[8]

- Meridian's Harapaki wind farm;
- Meridian's Ruakaka Energy Park (solar and battery);
- Contact's Tauhara geothermal plant;
- Mercury's Turitea wind farm;
- Tilt's Waipipi wind farm;
- Top Energy's Ngawha geothermal expansion;
- Lodestone Energy's five solar farms in Northland, Coromandel, and Bay of Plenty;
- Christchurch International Airport's recently announced Kōwhai Park energy precinct with up to 150MW of generation and an initial $100 million investment commitment from Solar Bay; and
- Hiringa's investment with Balance in a 24MW wind farm;
- The $40 million debt facility provided by the New Zealand Green Investment Fund to enable SolarZero to develop up to 40MW of commercial solar; and

[8] Other examples are included in MBIE's *Energy in New Zealand 2021* page 30, although the frequency of recent announcements and commitments means the MBIE information is already out of date.

- the 20-year electricity offtake agreement between Tilt and Genesis that will enable the construction of the 75MW Kaiwaikawe Wind Farm located near Dargaville.

These are examples of the market facilitating new renewable generation from diverse sources and proving that there are no barriers to entry (other than those that shareholders in those entities may impose by requiring an adequate return). There is nothing stopping any retailer or industrial consumer from investing directly in new generation or entering Power Purchase Agreements to support new generation.

The investment delays noted by the Authority due to consenting, demand uncertainty associated with NZAS, and government policy would have occurred even in a hypothetical perfectly competitive market.

If market power is exercised, the Authority has the tools available to address it

The Authority introduced new trading conduct rules in June 2021. These rules require that "where a generator submits or revises an offer, that offer must be consistent with the offer that the generator, acting rationally, would have made if no generator could exercise significant market power at the point of connection to the grid and in the trading period to which the offer relates".

If, despite the lack of evidence, the Authority continues to suspect the exercise of market power over the review period (to June 2021), then the next question would be whether those concerns are addressed by the new trading conduct rules which have been in operation for the last six months.

Unless the new trading conduct rules are deficient, enforcement by the Authority and Rulings Panel can be expected to address any concerns about the exercise of market power. The Authority has implemented a rigorous monitoring process with weekly trading conduct reports and a dashboard of key measures. We would expect the Authority to lay formal complaints with the Rulings Panel if potential breaches of these rules are identified.

The NZAS contract is efficient and benefits New Zealand

Meridian does not consider the NZAS contract to be an example of inefficient price discrimination. The Authority's analysis that leads it to that conclusion is flawed and makes several erroneous assumptions regarding Meridian's opportunity cost, and the willingness to pay of NZAS. Meridian will demonstrate in this submission that:

- Meridian did *not* sell to NZAS below its opportunity cost;
- household electricity prices would not likely have been significantly affected by a smelter exit;
- an extended exit deal with NZAS had wider benefits to New Zealand and was widely supported at the time;
- NZAS would likely have stayed even if an agreement was not reached in January 2021;
- the Authority's analysis is based on untestable assumptions about consumer willingness to pay, contains calculation errors, and does not recognise the impact of a smelter exit on transmission prices; and
- the intervention options contemplated exceed the Authority's mandate and risk significant consumer detriment because there is no problem to address.

Meridian's objective in the negotiations with NZAS that preceded the signing of the extended exit deal was to facilitate a longer exit of the smelter in a way that supported our commercial interests and also helped to manage the inevitable disruption to the electricity sector and the Southland community. The agreement gave Meridian time to build, plan, or facilitate new projects that would alleviate much of the wasted renewable resource that would otherwise have occurred with a smelter closure.

We were transparent with the market at every stage about our offer of an extended exit deal including keeping key Government agencies like the Commerce Commission briefed. The information presented by the Authority tells a different story and a reader may infer that Meridian was attempting to create 'scarcity' through the extended exit deal – this is a gross mischaracterisation of Meridian's intentions and the dynamic operation of the wholesale market that we reject in the strongest terms. Meridian is fully aware of its responsibilities under the Commerce Act, the Electricity Industry Act, and the Code. At all times Meridian acted on advice, in accordance with the law, and in an ethical manner. Meridian's intention was not to create scarcity but to derive the best value we could from Manapōuri generation that in an exit would have been wasted or of very little value to Meridian in the short term.

Meridian did not sell below opportunity cost

The Authority's suggestion that Meridian was willing to sell to NZAS at below its opportunity cost is wrong because the Authority's calculations:

- are based on prices at Benmore rather than at Manapōuri and make no attempt to adjust for nodal price differences in a smelter exit scenario;
- make no effort to account for the value of smelter demand response and price separation provisions in the contract which can be called on when lake levels are low – this is factored into the NZAS price; and
- assumes ASX futures prices fully anticipated a smelter exit after the contract termination and would not have fallen further upon a confirmed NZAS exit, when in reality there remained considerable speculation on that point and ASX prices likely factored in some probability that the smelter would remain.

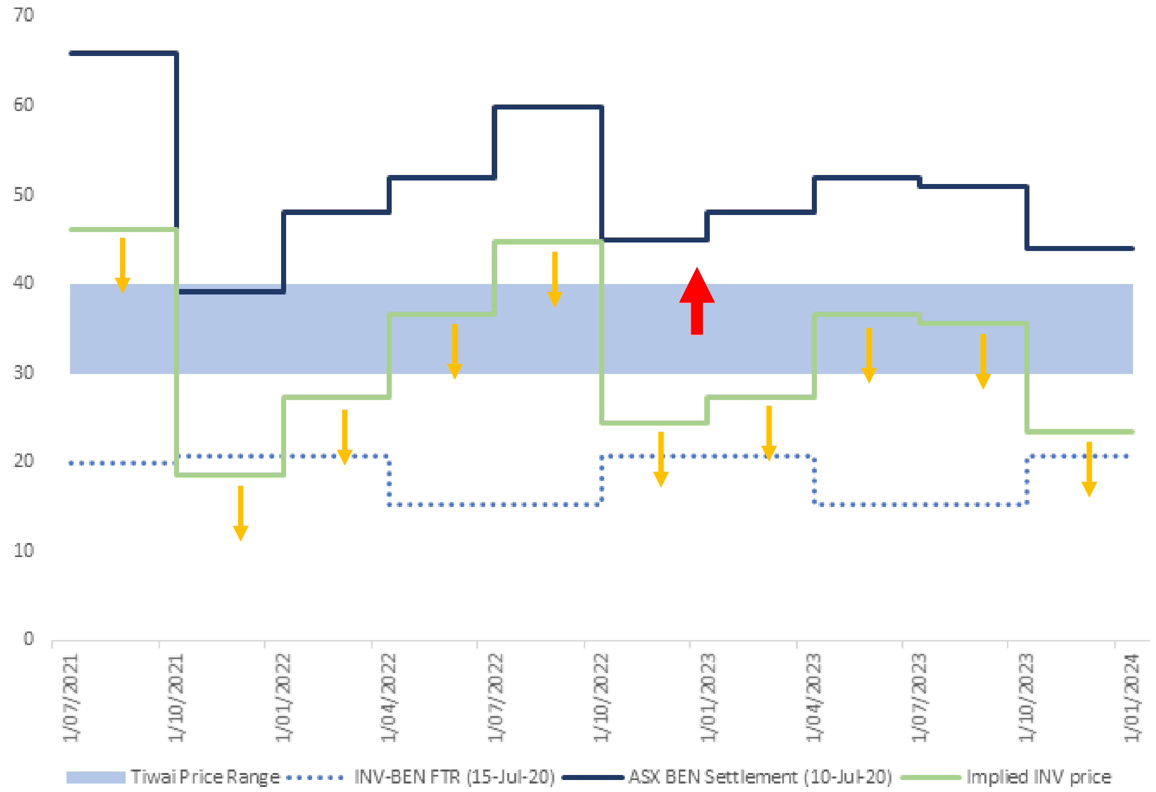
The Authority has not accounted for nodal pricing in its calculations. With transmission constraints limiting transmission out of Southland until completion of the Clutha Upper Waitaki Lines Project (CUWLP), and out of the South Island for much longer in a smelter exit scenario, it is likely that lake levels would rise and significant spill would occur. The value of that spill must be accounted for as well as the duration of high lake levels during which nodal prices (particularly in Southland) would be very low indeed. Instead of factoring this into its calculations, the Authority compares the NZAS contract price to ASX futures prices at Benmore. At the time the staged exit was originally offered to NZAS in July 2020, the CUWLP was scheduled for completion in winter 2023. As a result, we expected that in the event of a smelter exit, prices at the Manapōuri node would be significantly lower than prices at the Benmore node until transmission upgrades were completed (those low prices likely being accompanied by corresponding spill at both the Clutha and Manapōuri hydro schemes). Even once the lines upgrades were completed, prices at the Manapōuri node were expected to be significantly lower than at Benmore.

Below at figure 2, is an assessment of what a reasonable estimate of a derived price for Meridian's Manapōuri generation would be if NZAS had ceased operations. The figure below replicates the Benmore ASX forward quarterly prices from the day after the smelter's termination of contract in July 2020, as used in the Authority's papers.

The Invercargill to Benmore Financial Transmission Right (FTR) prices at the time have been added[9] as well as the Southland forward prices that this implies (the green line). We have done this because it appears to go to the heart of any concern the Authority may have that the NZAS price may not be an efficient price. This is not a Meridian view; it is the objective market view of nodal price differences at the time.

Adjusting ASX prices using the relevant Invercargill to Benmore FTR prices, indicates the market's expectation of achievable prices for Manapōuri generation, given transmission constraints and losses out of Southland. As can be seen in figure 2, once adjusted for nodal price differences, the NZAS price range is slightly higher on average than the green anticipated price for Manapōuri generation in a smelter exit (ignoring for now the arrows).[10]

Figure 2: ASX Benmore forward curve on 10 July 2020 adjusted for nodal price differences



[9] By averaging monthly FTR prices from the two FTR auctions immediately following the NZAS termination of contract and matching them with ASX quarters. The second auction following termination included FTRs for months after the expected completion date for the CUWLP and showed that the market still expected nodal price differences of $10 between Benmore and Invercargill. Note the Authority's analysis is based on the market's expectations at the time of contract termination and at that time the expected completion date for CUWLP was further in the future and uncertain. Accordingly, the pre-CUWLP completion FTR prices beter reflect the markets expectation of nodal price differences at the time of termination.

[10] Using the Invercargill FTR node as a proxy for Southland or Manapōuri prices.

In addition, the contract with NZAS includes two provisions that offer optionality to Meridian that ASX contracts do not. These are “price separation” and “smelter demand response” provisions, both of which potentially apply or can be called on when hydro lake levels are low. These aspects of the contract provide considerable value to Meridian and that value is reflected in the price captured within the NZAS contract. The efficiency of the NZAS price relative to the ASX alternative increases further once the value of smelter demand and price separation clauses are factored into the assessment (this effectively enables Meridian to discount the NZAS price and if backed out would lift the effective NZAS price as indicated by the red arrow).[11] As Carl Hansen points out in the attached report, the option value for the future of NZAS remaining should also be accounted for – backing this value out of the contract would have a similar effect and lift the effective NZAS price further.

The ASX prices at Benmore also reflected a probability weighted view of an NZAS exit rather than a view of exit as a certainty. There remained considerable speculation, even after the contract termination, as to whether NZAS would stay or go with many market participants still expecting some form of transition agreement to be reached between Meridian and NZAS or the Government and NZAS. As an example, an analyst report from Macquarie shortly after the 9 July 2020 contract termination noted that:[12]

> “[The] market may continue to weigh the probability that NZAS will a) ultimately close from 2021, b) secure recut electricity supply deal/s, c) back-down and sign contracts under offer or d) be divested. We continue to think the probability of a closure looks low given our view that the smelter is EBIT break-even at current LWM price and profitable adjusting for electricity price concessions on the table, RCP benefits from April this year and higher EITE unit trading on current spot NZU prices.”

This proves that some analysts considered the ASX had further to fall once a smelter exit became a certainty. If a guaranteed exit was factored into ASX futures prices, they would have been lower still as indicated by the yellow arrows in figure 2. These even lower prices in a definite exit should be expected by the Authority as the duration of spill or high lake levels would have result in very low offer prices for Clutha and Manapōuri generation for significant periods of time.

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[11] The effect of the “price separation” provisions in the NZAS contract are to reduce the contract quantity to the level of Meridian’s Southland generation during periods of low hydro storage when significant price differences arise between Benmore and Southland prices – the provisions are explicit contractual recognition of the potential for significant nodal price differences in this part of the grid.
[12] Macquarie *NZAS termination 9 July 2020*.

In his attached report, Carl Hansen also points out that "the irreversibility of an NZAS exit means that failure to agree a new short-term contract forecloses future opportunities for the parties to create additional value for their relationship. Conversely, agreeing a short-term contract keeps the options alive."[13] That future option value should be accounted for in the Authority's analysis and would further increase the effective value of the contract price.

The Authority seems to suggest the "effective" price of the NZAS agreement is lower than the price in the contract because it replaced the previous contract price. Logically that analysis is flawed – the Authority should consider the contract as a new transaction in the same way it would assess a transaction with a new consumer for that load. However, even if the Authority takes into account some form of implied discount due to early termination of the previous contract, the other adjustments described by Meridian above cannot be simply ignored and would mean the effective contract price is above the adjusted ASX benchmark.

As demonstrated, any reasonable assessment should conclude that the NZAS price was higher than the likely alternative prices in an exit scenario. Meridian did *not* sell to the smelter below its opportunity cost.

Household electricity prices may not have been significantly affected by a smelter exit

NZAS has been a feature of our electricity sector for 50 years. The sector has evolved with the smelter in place. However, the wholesale electricity market is dynamic and adjusts over time, it is not static. If the smelter were to leave, a new equilibrium with a different generation and demand mix would evolve. This would potentially include the retirement of least-efficient thermal plant and the exploration of new large demand growth opportunities in the South Island or elsewhere. Over the medium term we would still expect the average wholesale price to approximate the Levelized Cost of Entry (LCOE) of new generation required to meet demand. This is always Meridian's expectation and has been proven to be true in the long-term, even if short term deviations naturally occur from time to time.[14] Seen in that context, the contract price that is at any one time in place between Meridian and NZAS is just a value exchange between two companies.

[13] *CSA Report* page 11.
[14] Electricity Price Review *First Report* page 33, available at: https://www.mbie.govt.nz/dmsdocument/3757-first-report-electricity-price-review-pdf.

Any potential impact on wholesale prices would be relatively short term in nature and due to short run disequilibrium from a demand side shock rather than long term fundamentals. While it is reasonable to expect a temporary wholesale price adjustment following a smelter exit, market equilibrium would be restored after a relatively short period. It is therefore not reasonable to expect an immediate and sustained impact on household prices following a smelter exit. As noted in Enerlytica's commentary, the Authority's suggestion that households are paying $200 per annum to subsidise NZAS is "at best provocative".[15]

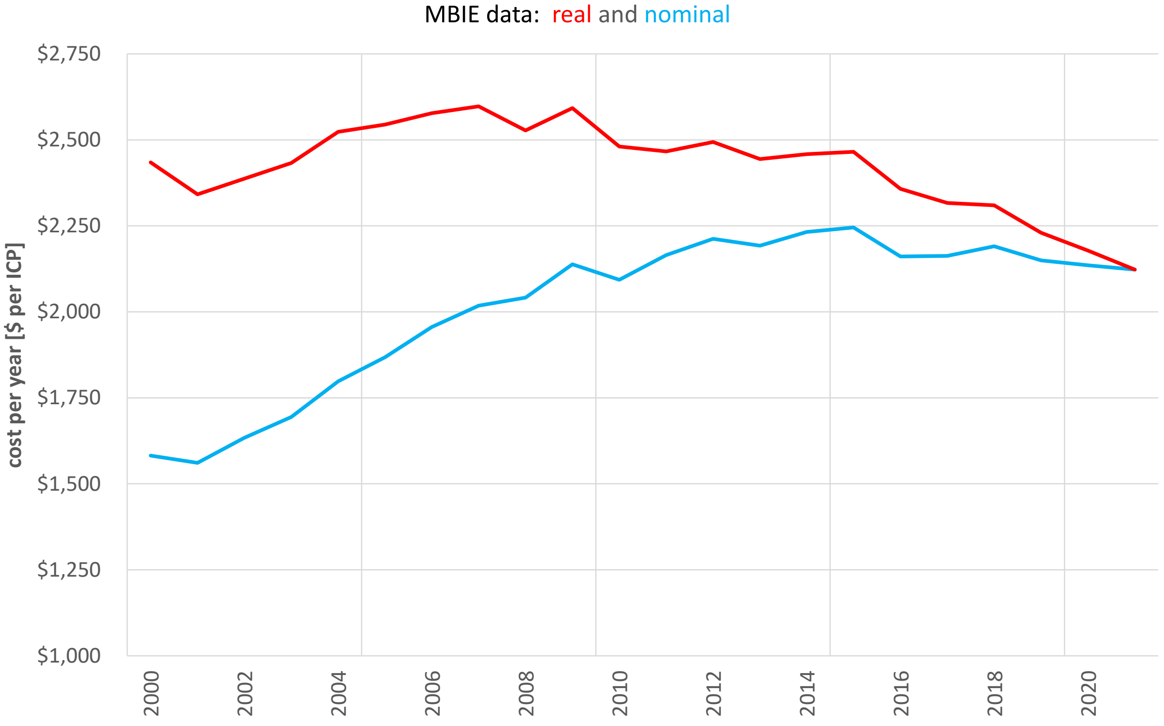
It is also debateable to what extent wholesale price reductions would quickly flow through to retail, as retailers typically take a longer-term view when assessing their tariffs. This has been very evident over the last 3 years as most residential electricity consumers have been insulated from the impact of relatively high wholesale prices. Most households are on fixed price contracts and retailers take a long term view of pricing to shelter households from short term wholesale volatility, be it seasonal or driven by other events. For example, during the review period, despite high wholesale prices the impact on households has been muted. Pricing data from the Ministry of Business, Innovation, and Employment[16] (MBIE) shows that real household prices have fallen year on year for the year to March 2018, 2019, 2020, and 2021. Even looking at the energy component of prices in isolation, household prices fell in 2018, 2019, and 2020. The energy component of household prices finally increased in 2021 but only by 7 percent (compared to average wholesale prices which more than doubled in the review period relative to the period prior to the review).[17] Furthermore, the MBIE data in figure 3 below, shows that annual residential power bills have been falling in real terms since 2009.

[15] Enerlytica *New Zealand Electricity* 28 October 2021.

[16] https://www.mbie.govt.nz/assets/Data-Files/Energy/nz-energy-quarterly-and-energy-in-nz/QRSS-September-2021.xlsx

[17] According to the Information Paper wholesale prices averaged $67/MWh prior to the review period (2009 to 2018) whereas wholesale prices averaged $119/MWh in 2019, $105/MWh in 2020, and $239/MWh in the first 6 months of 2021 (or a simple mean of $137.4/MWh over the review period).

Figure 3: MBIE annual household electricity bills



It is not reasonable for the Authority to assume a smelter exit event would play out differently and that retailers would suddenly take a short term view in pricing household tariffs; retailers may continue to take a longer-term view of household pricing.

An extended exit deal with NZAS had wider benefits to New Zealand and was widely supported

Meridian transacted with NZAS acting in its commercial self-interest and for the reasons described above. However, it is important to put NZAS' decision-making in the context of the views of other agencies who supported its continued operation and to recognise the broader benefits of the smelter beyond the Authority's focus on the electricity market.

In 2020 NZAS estimated that it contributed $482 million per annum to the New Zealand economy including through salaries, partnerships, in-kind support, taxes, and total national supplier spend. According to NZAS, it generates just under $1 billion per annum in export revenue and creates 2,260 direct and indirect jobs. The Authority has a narrow statutory remit to promote the long-term benefit of electricity consumers. The Authority is not well placed to consider benefits beyond the electricity market. The review papers reflect this narrow focus and do not consider the wider New Zealand Inc. benefits of NZAS remaining in operation.

The previous Government made a $30 million dollar payment to NZAS in 2013 to assist them to continue smelter operations. In the last election, given the potential impacts of an NZAS exit on jobs and the economy, almost all political parties committed to and campaigned on policies keeping the smelter operating for at least a transition period.

The current Government made an offer to NZAS to incentivise them to stay. Government officials held negotiations with Rio Tinto in relation to a possible deal that would involve an extended closure period and commitments around environmental remediation at Tiwai Point.[18] We also briefed government officials on Meridian's proposal.

The Authority itself made last minute changes to the prudent discount policy in the Transmission Pricing Methodology (TPM) that were requested by NZAS to enable NZAS to apply for a significant discount on its transmission bill.[19] Further to an industry workshop convened by the Minister and attended by the Authority, Transpower estimated this discount could be worth up to $20 million per annum to NZAS.

During 2020, Meridian confirmed publicly and in discussions with the Authority that it had put a proposal to NZAS with the objective of allowing NZAS to close the smelter over up to four years. At no time were concerns raised by the Authority.

To be told by the Authority a year later that the NZAS contract may in fact be harmful to consumers is hard to reconcile with its apparent comfort at the time, its amendments to the TPM guidelines, and with the Government's support for an extended closure period. It appears to come from the Authority now focussing on only potential short-term pricing implications and not on the broader benefit to New Zealand Inc.

The Authority says it would not unwind the NZAS contract and that it is more concerned the contract may be evidence of a wider problem, namely the potential for inefficient price discrimination in large industrial electricity contracts. It would be an unusual policy outcome if the Authority discouraged market participants from contracting with large industrial users of electricity out of misplaced concern as to what this might do for residential electricity prices

[18] See the correspondence between Rio Tinto and Ministers here: https://www.rnz.co.nz/news/national/445996/documents-reveal-government-s-multi-million-offer-to-rio-tinto-despite-ruling-out-a-subsidy

[19] In February 2020 the Authority's supplementary consultation paper consulted on changes to the TPM guidelines that would make it easier for NZAS to claim a prudent discount on its transmission bill: https://www.ea.govt.nz/assets/dms-assets/26/26354TPM-supplementary-consultation-Feb-2020.pdf. The change was a direct response to Rio Tinto submissions.

in a static view of the market. Consumers need jobs and a healthy economy as well as affordable electricity. Closing down an industry that was previously a significant consumer of electricity (or restricting a similarly electricity-intensive new industry) may in the short term bring a reduction in wholesale prices but within the dynamic electricity sector supply and demand would then adjust, a new market equilibrium would form, and prices would revert on average to the LCOE of new entry. In the meantime, the broader economic cost to New Zealand in jobs, supply chain contracts, and export earnings would potentially be huge.

Meridian is particularly concerned at the implications of the Authority's comments on efforts to electrify the New Zealand economy and meet emissions targets. Meridian is actively encouraging new large electricity consumers and uses, including:

- a joint Southern Green Hydrogen project with Contact to evaluate the opportunity to produce green hydrogen in Southland[20], which is being conducted in accordance with strict competition law protocols;
- enabling the development of a hyperscale data centre near Invercargill; and
- working with customers to switch from coal-fired boilers to electric boilers.

We believe that these electrification projects will contribute positively to the New Zealand economy and will assist with decarbonisation. However, all these decarbonisation efforts now face regulatory uncertainty at a critical juncture, right when investment decisions are being made for the future. In particular, Meridian and Contact have short-listed parties following the expressions of interest process for the Southern Green Hydrogen project and are now proceeding to a request for proposal and further commercial negotiations over the next few months.

In principle, agreeing to contract with new large-scale consumers has the same effects as contracting with NZAS to postpone their exit plans. Given the need for significantly increased electrification to meet 2050 emissions targets, discouraging the large scale electrification of industry through price floors or restrictive contractual terms would be counterproductive. In market economies, efficient prices are arrived at through negotiations between willing buyers and willing sellers. It is highly unlikely that the Authority would be better placed than parties to a transaction to determine what is (and is not) an efficient price bearing in mind factors such as:

- the impossibility of the Authority understanding the willingness to pay of parties in a commercial negotiation;

[20] https://www.southerngreenhydrogen.co.nz/

- the imperative to decarbonise the New Zealand economy and the reputational value associated with being a part of that;
- the value of demand response that is expected to be a part of many such industrial contracts in future; and
- the long-term nature of electricity contracts to support significant capital investments in long-life industrial assets.

NZAS would likely have stayed even if an agreement was not reached in January 2021

Given London Metal Exchange aluminium price changes since July 2020 and January 2021, it now seems likely that, if Meridian and NZAS had not agreed on a staged exit deal, NZAS would have approached Meridian at some stage after January with improved terms to stay. The point being, even the Authority's assumption that NZAS would have exited in August of 2021 had Meridian not made NZAS the offer it did, is flawed. Enerlytica's Tiwai-ometer indicated that the break-even power price for NZAS had risen to $140/MWh by August 2021.[21] In that context care needs to be taken with making definitive statements about the supposed impact of the changes to the NZAS contract agreed in January 2021 and the NZAS willingness to pay assumption that underpin the Authority's calculations of inefficient price discrimination.

NZAS would not have known all of that with perfect foresight in January 2021 but it would have had some expectations about future aluminium prices, and the likelihood of them remaining low for an extended period. These longer-term expectations must be accounted for in any assessment of willingness to pay.

The Authority's analysis is based on untestable assumptions about consumer willingness to pay

The Authority recognises that price discrimination can be a legitimate practice. However, according to the issues paper the Authority is only concerned about *inefficient* price discrimination. Appendix B of the Authority's issues paper makes it clear that a high willingness to pay does not result in inefficiency but a low willingness to pay can. The Authority is only concerned about *inefficient* risk contracts when willingness to pay is low and electricity is not allocated to its highest value use. As summarised by the Authority:

[21] Enerlytica *Tiwai-ometer* 20 August 2021.

> "If NZAS were, in principle, prepared to pay 'market' prices, then the prices the rest of New Zealand pays for electricity would reflect underlying fundamentals of supply and demand and the public policy concerns would be mitigated."

Willingness to pay is an unobservable and unmeasurable concept and seems to be the key determinant for the Authority to judge what is (and is not) and efficient contract. As noted in Carl Hansen's report, the Authority acknowledges NZAS had strong bargaining power[22] and "this means it is incorrect to infer an upper bound to NZAS' willingness to pay from decisions to terminate its previous contract, as giving notice can be part of hard-ball bargaining".[23] Only NZAS knows its true willingness to pay at any point in time and willingness to pay is likely to be based not on a static snapshot but rather on long-term expectations of all relevant factors including aluminium prices and profitability.

The economic analysis put forward by the Authority also effectively suggests that if industries fall on hard times and have low willingness or ability to pay then they should not receive power. When a firm shuts down because of low prices for the commodity it is producing, the consumer no longer reveals their willingness to pay for electricity and all future opportunities are lost. Critically, if the Authority's logic is followed through to its conclusion, society would forgo benefits when prices for that firm's commodity return to normal and its willingness to pay is restored. Volatility in profitability is common for many industries and it would be an unusual outcome if regulation required firms to close when they go through an unprofitable period, just because the allocation of electricity was deemed to be inefficient over the short term.

Willingness to pay and market price levels are ever-changing so it should stand to reason that inefficiency might occur whenever willingness to pay is low. However, the Authority seems to only be interested in welfare gains and losses when offers are made and when they are accepted.[24] It is not clear why that is the case as the rationale presented by the Authority could identify allocative inefficiencies in a static snapshot of risk contracts at any time. Firms go through profitable periods and unprofitable periods with different willingness to pay at different points in time. Even if we only look at the time offers and agreements are made, we question what would happen to a large industrial consumer seeking a long-term hedge contract during a time of electricity market stress when they have relatively low willingness to pay. Should generators ensure their energy hedge price meets or exceeds

[22] *Information paper* page 16.
[23] *CSA Report* page 10.
[24] *Issues paper* paragraph 5.10.

the short-term "market price" least inefficiencies are created? The Authority seems to in effect be saying that businesses should *not* look through short-term volatility in their contracting practices and that when willingness to pay is low for a period relative to short term wholesale electricity prices, closing down is the most efficient approach.

The literature indicates that the demand curve is about both willingness and ability to pay. Therefore, at its worst, the economic analysis put forward by the Authority effectively seems to imply that poorer consumers should be switched off first in dry years as they have the lowest willingness or ability to pay for power.

The efficiency loss calculations are wrong and in any event the impact of a smelter exit on transmission prices would offsets any efficiency losses

The attached report by Sapere Research Group reviews the literature on price discrimination and recreates the Authority's calculations of efficiency losses. According to Sapere:

> "The Authority wrongly characterises the Tiwai contracts as an example of inefficient price discrimination. Rather than an efficiency loss of $57 million to $117 million as arrived at by the Authority, the better measure of the total efficiency gains from the Tiwai contracts (relative to a scenario in which the smelter ceased production) is around $40 million to $120 million per annum, applying the Authority's assumptions consistently."

Even if (despite Sapere's analysis) the Authority still considers its calculations of efficiency loss to be reasonable, it should not draw conclusions on whether the NZAS contract is efficient in electricity market terms without also taking into account the share of the national transmission bill picked up by NZAS. The Authority follows the methodology set out in the appendices of the issues paper to estimate the size of the total efficiency losses that it claims may result from the NZAS contract. As described above, the Authority's exit price assumptions and NZAS willingness to pay assumptions are not supported by the evidence. However, in addition, any estimated efficiency losses would be offset by the fact that NZAS currently pays approximately $58.32 million per annum in transmission charges.[25] Upon a smelter exit, all other transmission customers in New Zealand would have to pay the NZAS share of transmission costs. Unlike the rest of the Authority's analysis, this cost is a certainty. The size of transmission cost covered by NZAS is broadly equivalent to the $57 million lower bound of the Authority's baseline assessment of total efficiency losses.

[25] If the new Transmission Pricing Methodology were implemented from April 2023 that number would reduce to approximately $44.7 million per annum. See: https://www.ea.govt.nz/assets/dms-assets/28/TPM-Proposal-Reasons-Paper-Appendix-B-Indicative-Prices-Transpower.pdf.

Regardless of the efficiency calculation for the electricity market, as detailed elsewhere in this submission, there are significant national benefits associated with the smelter remaining in operation that the Authority has not considered given its limited role as an electricity market regulator.

The intervention options contemplated exceed the Authority's mandate and risk significant consumer detriment because there is no problem to address

As noted above, Meridian does not consider there to be any evidence to substantiate the Authority's claim of inefficient price discrimination. All the Authority has identified is a theoretical problem, based on untestable assumptions, with no evidence of any problem in practice. As set out in Carl Hansen's attached report, there are serious problems with each of the Authority's intervention options because they are based on a flawed problem definition and fundamentally flawed analysis of price discrimination.

If, despite the lack of evidence of any problem, the Authority intends to regulate electricity hedge contracts in some way, it must follow a clear process and timeframe that will provide certainty to the market. The risks associated with regulatory uncertainty should not be underestimated. As pointed out in the attached Sapere report, the Authority's process to date has already created significant uncertainty and further uncertainty should be avoided.

The Authority needs to first also have a clear idea of how its jurisdiction fits with that of the Commerce Commission. The Authority is primarily a rule maker and has a statutory purpose to promote competition, efficiency, and reliability for the long-term benefit of consumers. Promoting efficiency does not mean assessing every individual transaction to ensure it is efficient. In contrast, the Commerce Commission enforces the Commerce Act's prohibitions on the misuse of market power (including predatory pricing) and agreements that have the purpose or effect of substantially lessening competition.

To the extent that an electricity contract discriminates on price, the risk that it might substantially lessen competition is already addressed by the Commerce Act and there is no clear role for the Authority. Many of the intervention options contemplated by the Authority would result in multiple regulators assessing the same contracts both with a competition lens in mind. The Commerce Commission is the expert competition regulator; we query whether it would be appropriate or useful for the Authority to give itself a duplicate function. Doing so would add significant cost and complexity to electricity risk contracts.

The Authority's proposal appears to be inconsistent with its previous understanding of the respective roles of the Authority and the Commission. In its interpretation of its statutory objective, the Authority states:[26]

> "The Authority interprets promoting competition to mean exercising its functions to facilitate or encourage stronger competition. The Authority is not focussed on the conduct of individual participants with respect to competition in the electricity industry as this is the responsibility of the Commerce Commission. Rather the Authority is focussed on improving the arrangements in the electricity industry to promote competition."

Furthermore, the Authority must show through cost benefit analysis that there will be a net benefit to consumers because of any chosen intervention relative to the status quo. All the initial options identified by the Authority entail significant risk of unintended consequences and direct limitations on the free trading of risk that will likely increase the costs of doing business in New Zealand. Based on the potential costs of all the intervention options identified, a net positive cost benefit analysis would seem unlikely, particularly given the lack of evidence of a real problem under the status quo that needs to be addressed.

If the Authority nonetheless proceeds to seriously consider some form of regulatory intervention, the chosen solution must be directly linked to the supposed problem identified.

In section 6 of the issues paper, the Authority broadens the areas it is concerned about to include contracts with non-integrated retailers without providing any evidence in support of those concerns. Those concerns are not even mentioned in section 5, entitled "Issues the Authority would like to address." The supposed incentives for generators to inefficiently price discriminate, even if proven to be a real problem, logically only apply to cases where a large load customer is considering entering or exiting the New Zealand market. The vast majority of bilateral risk contracts are effectively decisions to change the counterparty for a pre-existing hedge and therefore have no net effect on load and no impact on spot prices. Likewise, there is no way risk contracts with other retailers would fit within the supposed inefficient price discrimination problem as they do not result in a change in the supply and demand balance and therefore have no impact on spot prices. Solutions to address this unrelated non-problem have simply been tacked onto the Authority's review without any supporting analysis (in fact recent analysis by the Authority has dismissed this as not a

[26] https://www.ea.govt.nz/assets/dms-assets/9/9494statutoryobjective.pdf.

problem).[27] The scenario of refusing to trade with a retailer or raising rivals costs to foreclose retail competition is not realistic – retailers have a number of potential counterparties with whom they could enter into hedge contracts and can play them off against each other to reduce any perceived "premium". The ASX futures market also provides exchange traded products that any retailer can purchase. Because of market making, there is significant open interest in ASX futures, and the Authority has already determined in its hedge market enhancement workstream that retailers can build significant positions via ASX contracts, at prices that are a fair indicator of future spot prices. Furthermore, any contract that was entered into with the purpose of foreclosing or forestalling entry at the retail level and any attempt to unjustifiably refuse to supply a downstream competitor with an essential input would already be addressed under the Commerce Act.

Of the intervention options contemplated, a prohibition on use-it-or-lose-it clauses in large risk contracts could be less harmful to consumers than other options. However, the Authority will need to consider the negative impact on investment certainty for generators. Use-it-or-lose-it clauses serve legitimate pro-competitive purposes as they give generators increased certainty regarding the physical load associated with a contract and therefore enable generators to invest more confidently. Given the need for significant investment in new renewable generation over the next decade, regulation which makes that investment more challenging may be counterproductive.

The Authority would also need to consider the fact that physical supply contracts are implicitly use-it-or-lose-it contracts for energy consumption at a point of connection. Restrictions on use-it-or-lose-it clauses in financial hedge contracts could simply drive increased use of physical supply contracts.[28] If the Authority did not consider that a good outcome it would have to contemplate a far more sweeping change in the electricity market to require all contracts (physical or otherwise) to be on-sellable. This would be an extreme measure with the potential for significant unintended consequences.

The practicalities of on-selling hedge contracts would also need to be considered. Large industrial risk contracts are not necessarily homogenous and can include bespoke

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[27] For example, the Authority's consultation paper *Internal transfer prices and segmented profitability reporting* at paragraph 3.41 stated that "It has been suggested that independent retailers should be able to buy electricity from generator-retailers at their prevailing ITPs within the period. The Authority does not support this proposal as: (a) the Authority's analysis of generator-retailers' ITPs suggests that third parties, including adequately capitalised independent retailers, can buy electricity in the range of ITP levels if they adopt similar hedging strategies to those used notionally by generator-retailers for setting their ITP. The four largest generator-retailers each provide futures market making services on an unpaid basis which facilitate hedging by independents."

[28] It is worth noting that the smelter agreement was originally a physical supply agreement.

provisions such as the ability to call on demand response. This might make on-selling to a third party challenging. As Carl Hansen points out in the attached report, "as risk management instruments, CFDs play the crucial role of allowing generators and consumers to better match their respective requirements to reduce risks and costs for both parties. It makes no sense for a tailored CFD to be transferable to other consumers with risk profiles that poorly match the generator's portfolio, or to other consumers with higher credit default risk."

The Authority might also like to consider:

- Increased disclosure of contracted thermal fuel. This is something that Meridian has long advocated for to increase the efficiency of the wholesale market. There is excellent information available to the market about energy stored in hydro lakes but almost nothing is public about the volumes of gas contracted or otherwise available to thermal generators. The Authority's efforts in this space have only resulted in the administrative burden of quarterly disclosures by all major participants to the Authority rather than any increase in public disclosure. In its June 2021 briefing to the Minister, the Authority identified information about gas availability as a "key issue throughout the event" and noted that even with its information gathering powers "the Authority is limited in its ability to require information of a standard that is needed to resolve any ambiguity regarding gas available for thermal generation, unless that information is held by electricity generators. That is, the Authority is entirely reliant on anecdotal information and the good will of gas sector players for information". The situation is even worse for market participants with no exposure to the gas market. This lack of information disclosure should be addressed with urgency in collaboration with the Gas Industry Company (GIC) if required.
- Working with the GIC on a futures market for gas. The industry would benefit from a gas forward curve in much the same way it has the ASX electricity forward curve. Wholesale prices have been significantly affected by gas prices and deliverability. Participants may question the validity of ASX futures prices in the absence of being able to see what underlying gas prices are expected to be over the same time horizon. Gas industry participants could provide market making in much the same way as the four largest generators do in the electricity sector.
- Increased transparency for large industrial contracts over a set MW threshold though a requirement for large industrial consumers of electricity like NZAS to contract or recontract their electricity hedges via public tenders. Such transparency measures could increase competition and mitigate any potential for inefficient price discrimination.

We selfishly see some advantages to the pre-approval process contemplated by the Authority for large contracts. There is always a high degree of controversy associated with Meridian’s contract with NZAS and we would welcome the opportunity to have a regulator share responsibility for decisions that may impact on the ongoing operation or closure of the smelter and the jobs and livelihoods that depend on it. Pre-approval would also avoid situations like the present one where almost a year after the fact the Authority questions the contract and Meridian’s intent. We would much prefer to have been able to discuss with the Authority any concerns it had at the outset. However, while it would assist Meridian in its decision-making and insulate us to some extent against potential reputational damage, the politicised nature of an approval process, the lack of any well-defined problem to be addressed, the Authority’s inability to consider wider benefits to New Zealand, and the overlaps with the Commerce Commission’s jurisdiction do not give us confidence that such an intervention option would pass a cost benefit assessment or ultimately result in decisions that were in the best interest of New Zealanders. Meridian also doubts that the Authority wants to be the party responsible for preventing the transition to a renewable future by rejecting industrial electrification contracts that it perceives as being “too cheap”.

The Authority’s strategy reset states that it wants to electrify the economy and that “we need to promote a stable investment environment with robust rules and clear price signals to unlock the potential for more renewable generation and ensure the transition is as efficient as possible.” Meridian agrees. However, by proceeding to contemplate a range of intervention options that do not address any identified problem, the Authority in fact risks weakening investment signals and creating uncertainty regarding the rules that will apply to the trading of risk which underpins investment. If it wants to deliver on its strategy, the Authority must exercise caution and ensure that its own monitoring and Code making processes do not needlessly increase instability and uncertainty in the investment environment at this critical juncture.

In respect of the structural policy options put forward by the Authority, Meridian would be open to renewing the Virtual Asset Swap arrangements, which are due to expire in 2025. However, implementing any of the options would not address any identified problem and would presumably require support from the Government. We will engage with the Government should a problem be identified, and should the Government wish to contemplate these ideas further, having first considered the implications for sovereign risk and the chilling of generation investment at precisely the time the Government is encouraging more renewable generation investment.

Appendix A: Detailed response to the information paper

Introduction

This section of Meridian's submission responds specifically to the detailed analysis in the Authority's information paper, namely the analysis of wholesale market structure, conduct, and performance that attempts to explain unknown drivers of the increase in spot prices over the review period. The information paper uses a traffic light system to summarise the Authority's observations for a range of indicators.

The information paper refers to both linear and dynamic regression analysis of spot prices in the review period relative to the pre-review period. According to the Authority:[29]

> "The results from our dynamic model are consistent with the linear model we fitted earlier. Again, the model confirms what we qualitatively observe about the spot market: that high spot prices tend to coincide with low wind, low storage, high gas spot prices and other gas sector disruptions, and high demand. Both the linear model and dynamic regressions provide evidence to support the hypothesis that spot prices are determined by the balance of supply and demand."

However, the Authority also identifies a sustained upward shift in spot prices that the regression cannot explain. The regression cannot determine whether this shift was attributable to:

- limitations in the model itself (no regression perfectly captures all variables);
- uncertainty about the gas market influencing bids and prices; and/or
- generators exercising substantial market power.

According to the Authority: "the detection of a structural break in late 2018 supports the proposition that some of the sustained upwards shift in prices post-Pohokura could be due to gas supply issues. But it is not conclusive evidence."

The Authority speculates that some of the sustained uplift in wholesale prices could be due to prices not being determined in a competitive environment and relies on the structure, conduct, performance analysis in the information paper to say that it "observed some

[29] *Information paper* paragraphs A.34 and A.35.

evidence to suggest that prices may not have been determined in a competitive environment." This section will show that the Authority does not have *any* evidence, merely speculation and false positives because its analysis does not recognise the extent of uncertainty about gas supply, nor does it recognise how hydro storage is managed to ensure security of supply over time and operate hydro generation chains.

We do not repeat here Meridian's agreement with the overall conclusion, cited by the Authority's peer reviewers, that there is no evidence market power has been exercised. Instead, this section engages with the Authority's traffic light assessments that attempt (without success) to identify a market power reason for the perceived price uplift. In this section we:

- make general observations about the lack of a clear rationale for the traffic lights, the selection of indicators and the consideration of the indicators in isolation;
- provide Meridian's suggested reframing of the traffic light summary of structure, conduct and performance observations (Table 2 in the information paper); and
- consider each of the structure, conduct and performance measures and the indicators selected for the Authority's analysis and comment on the suitability of each indicator, whether other indicators could be considered, and what might be observed about the market through the lens of each indicator.

There is no clear rationale underpinning the traffic light system and it is not clear why the selected indicators have been chosen and considered in isolation from each other

There is no clear and consistent rationale behind the traffic light system

The Authority must ensure that its traffic light summary in Table 2 of the information paper is supported by the underlying analysis and uses expectations of workable competition as the benchmark.

Table 2 in the information paper appears to apply different benchmarks for different indicators rather than a consistent approach. Summaries for some of the indicators suggest that the Authority is looking for a change in patterns when comparing the review period with the pre-review period. However, for other indicators the Authority's "expectations" for each indicator are qualitative and are not necessarily concerned with how structure, conduct, and performance changed during the review period, i.e. the pre-review period does not always appear to be the benchmark and at times the Authority instead seems more concerned with whether the review period meets some idealised state of perfect competition.

The Authority does not describe in any detail what the benchmark might be for its idealised state of competition. The information paper is not explicit and provides mixed signals on the competition benchmark it is applying. For example, the information paper states that in a competitive market the Lerner Index is equal to zero.[30] This implies the Authority is interpreting competition to mean perfect competition as a zero Lerner index will only occur in a perfectly competitive market, and that anything less than perfect competition will be marked orange or red by the Authority. As noted by Carl Hansen in the attached report, greater clarity and consistency from the Authority would be helpful and this could be achieved by explicitly stating it is applying the workable competition benchmark when assessing its competition indicators.[31]

Table 2 is constructed so that it compares a statement of the Authority's expectations in a competitive market with observations from the review period. We would therefore expect the traffic lights to be based on departure of observations from expectations, for example green would mean expectations are met, whereas red would mean expectations are not met. It is not clear from the information paper what an orange light means, but we understand from subsequent correspondence with the Authority that the indicator "raises qualified concerns about the competitiveness of the market." This contradicts acknowledgments made by the Authority for many of the orange indicators, that it cannot conclude anything or that the indicator is not particularly informative. Where that is the case, Meridian suggests no traffic light signal be used. This would be a more accurate and neutral representation and to say these indicators raise "qualified concerns" would not be evidence based and would be an error of judgement. Meridian's concern is more than mere optics because we understand that the Authority is considering a longer-term work programme to "turn each indicator green". This would be a problematic endeavour and questionable use of resources when it is acknowledged that many indicators do not offer any meaningful insight.

It is not clear why these indicators have been chosen over others

The current review is not the first time in the last three years that the Authority has reviewed the wholesale market. The Authority has looked at different indicators over the course of its

[30] *Information paper* paragraph 5.82.
[31] We note that one of the Authority's peer reviewers, Concept Consulting, is in sufficient doubt as to the standard being applied by the Authority that they explicity state their assumption that the Authority is applying a workable competition standard.

nine Market Performance Reviews[32] and Market Insights[33] published since the Pohokura outages in 2018. The Authority has reached different conclusions depending on its selection of indicators.

The Authority has used a different range of indicators in its annual reporting to the Minister and Parliament.[34] For example, in the most recent annual report the Authority reported on the following competition, reliability and efficiency statistics relevant to the wholesale market, summary results were also noted and were largely positive:

- **Net pivotal analysis –** the most net pivotal generator is still only net pivotal less than one per cent of the time. Overall, the long-term trend is downwards.
- **Hedge market concentration (HHI)** – HHIs were low overall for both monthly and quarterly contracts.
- **Concentration in the ancillary services market (HHI of reserves) –** the HHI for New Zealand has remained low and stable since the introduction of the national market for reserves
- **Pricing in scarcity events reflects opportunity cost, as measured by case-by-case analysis –** the high prices in early 2020 and May 2020 were investigated as part of Quarterly Reviews and a market commentary publication. This initial analysis found prices reflected market fundamentals.
- **Effective management of dry years or emergency events, as measured by case-by-case analysis –** the beginning of 2020 with low storage in the North Island and constrained export north, plus the high prices in May 2020 have been discussed in Quarterly Reviews and a market commentary publication.
- **Capacity and energy margins are within efficient bounds or are moving towards those bounds, as measured by the annual security assessment –** capacity and energy margins are moving towards the bounds set by the Board.
- **Investigation of reliability events does not identify systemic issues, as measured by case-by-case analysis –** the Rulings Panel issued penalty decisions on formal complaints in relation to the 2 March 2017 South Island restoration event

[32] Market performance review of Spring 2018; Market performance quarterly review - First quarter 2019; Market performance quarterly review - January 2020; Market performance quarterly review - April 2020; Market performance quarterly review - July 2020; Market performance quarterly review - October 2020; Market performance quarterly review - December 2020; Market performance quarterly review - March 2021 all available at: https://www.ea.govt.nz/monitoring/enquiries-reviews-and-investigations/
[33] Market insight - Electricity spot price increases - November 2019, available at: https://www.ea.govt.nz/assets/dms-assets/26/26029Spot-price-changes-in-2019.pdf
[34] See for example: https://www.ea.govt.nz/assets/dms-assets/27/27461D.11-Electricity-Authority-Annual-Report-2019-201272638.1.pdf

and the 25 January 2018 outage in Hamilton. The Authority published a Quarterly Review discussing events which occurred in November 2019 and the learnings for reliability. The review did not identify any systemic issues

- **Robust futures prices** – our 2019/20 work programme delivered projects aimed at improving liquidity and more projects are scheduled in the 2020/21 work programme.
- **Dry year prices reflect storage levels, as assessed by case-by-case analysis** – low North Island storage and a scheduled HVDC outage in early 2020 led to price separation as expected. Low North Island storage and generation outages led to high prices during May 2020. These two periods have been discussed in Quarterly Reviews and a market commentary report. Initial analysis suggests spot prices during these periods reflected the scarcity of supply.
- **Exceptional prices are justified by underlying fundamentals, as assessed by case-by-case analysis** – an investigation into the claim of a UTS suggests that spot prices may not have reflected underlying fundamentals during December 2019.[35]
- **Reducing constrained-on compensation** – constrained-on costs have been falling since 2011.
- **Increased occurrence of demand bids setting spot prices** – not yet measured.

It is not clear why the Authority would use one set of measures to assess the wholesale market and report those to the Minister then turn around a few months later and effectively say those statistics were not the right ones to be looking at or come to a different conclusion.

Strikingly, the Market Performance Review for the second quarter of 2020 includes a section titled: "Special Topic 2: Regression analysis of spot price drivers". That section details a regression analysis built by the Authority to consider spot price drivers. Amongst the usual drivers like storage and national electricity demand, the Authority tests whether various measures of competition (e.g. changes in HHI) affect spot prices. The results are clear and stand in stark contrast to the tone of the current review papers:

> "This model provides evidence to support the hypothesis that spot prices are determined by the balance of supply and demand and that these effects dominate any effects due to market concentration. Note that price being determined by underlying demand and supply indicates effective competition. The model confirms what we qualitatively observe about the spot market: that high spot prices tend to coincide with low wind, low storage, high gas spot prices and other gas sector disruptions, and high demand."

[35] Subsequently market prices were corrected by the Authority.

The same conclusions were reached in the Market Performance Review for the April to June 2021 quarter (released the day before submissions closed on the current review).[36]

Balanced indicators should not be duplicative, and each indicator should not be looked at in isolation

As noted by Carl Hansen in the attached report, looking at the measures together it is clear that Meridian's offers are consistent with offers in a workably competitive market. "It was the marginal generator only 27% of the time[37] and the Lerner index for those trading periods is volatile, even on a monthly-average basis.[38] This suggests considerable rivalry for dispatch, consistent with a workably competitive market in which a firm is unable to choose its profit by withholding output for a sustained period."

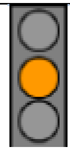
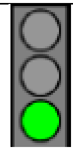
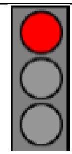
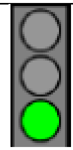
Carl Hansen also notes that to present a balanced set of meaningful indicators requires omitting meaningless or duplicative indicators or including them only for context and not as part of its traffic light summary of competition indicators.

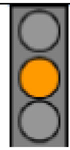
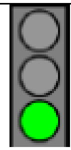
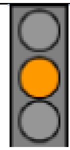
Meridian traffic light summary

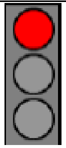
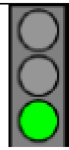
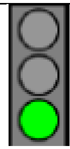
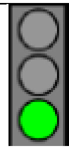
Table x below shows (in blue text) Meridian's suggested adjustments to the Authority's assessment and applies a more appropriate traffic light to each indicator based on those adjustments. The reasons for the suggested adjustments are detailed further in the rest of this section under the Authority's headings of structure, conduct and performance.

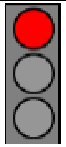
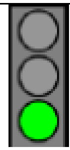
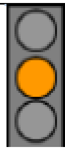
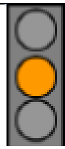
[36] https://www.ea.govt.nz/assets/dms-assets/29/April-June-2021-Quarterly-Report.pdf.
[37] Information paper paragraph 5.160
[38] Information paper pages 71 to 72

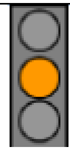
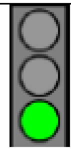
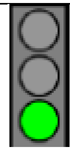
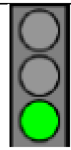
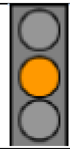
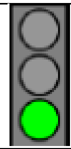
Table x: Meridian adjustments to the Authority's traffic light summary

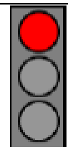
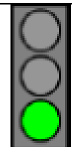
	Measure	Indicators used	What we would expect to see in a workably competitive market	What we observed Authority	Meridian	
Market structure	Seller concentration	Generation HHI	Low concentration reduces risk of any one firm unilaterally affecting prices, or of lasting collusion between groups of firms. A lower HHI means lower seller concentration.			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. The longer-term trend shows HHI very gradually falling indicating lower levels of market concentration over time. As the trend is no change or slightly positive it is not clear why the Authority has marked this orange. If it is because the indicator is not meaningful then it should not be used at all.
		~~Gross pivotal~~ Net pivotal	~~While the structure of generation in New Zealand means a generator may be gross pivotal a large percentage of the time, this won't change quickly over time in a competitive market. We would also expect a generally decreasing trend for each generator as new-entrant generation enters the market.~~ We would expect to see very few trading periods where any one generator had both the ability and incentive to raise wholesale prices. Ideally the frequency of net pivotal periods would remain low and decrease over time.			~~Meridian has historically been gross pivotal around 77 percent of the time, but in the review period this has increased to around 90 percent to 95 percent.~~ No generator was net pivotal more than 0.2% of the time during the review period and the measure shows improvement relative to the pre-review period.

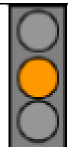
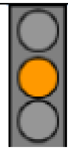
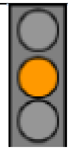
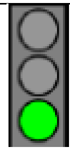
	Barriers to entry	Vertical integration	Low barriers to entry place pressure on incumbents to display competitive pricing behaviour. We would expect to see entry and expansion from a range of business models. [The remainder of this passage is not a description of what the Authority expects to see.] ~~Vertical integration may increase costs for new entrants by reducing liquidity in the forward market and reducing the demand for PPAs supporting new-entrant generation.~~			The level of vertical integration across all players has not changed and if anything shows a slowly decreasing trend. ~~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. However, hedges are freely available to stabilise revenue for non-integrated generators. Generation investment is occurring from a range of different businesses with a quarter of new projects owned by non-integrated firms, indicating that in practice barriers do not exist or can be easily overcome. Some indication of increased use of PPAs and potential PPAs is positive ~~means vertical integration is less of a barrier than it might have been~~.
Market conduct	Price-cost relationship	~~Offers over time~~	~~These should reflect underlying supply and demand conditions.~~		-	~~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 that 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).~~ [There is no clear indicator used here and the analysis seems to overlap entirely with the indicators below. The price of Meridian's non-clearing offers did change in response to the Authority's QWOP analysis of the 2019 UTS period, but not the quantities. This change in offer price had no impact on market clearing prices as volumes offered in those tranches would not clear in normal circumstances given the associated security of

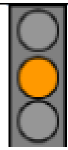
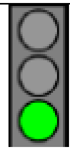
						supply risk for Meridian and New Zealand. It was done to meet what we perceived were regulatory expectations. Meridian and other generators commonly offer in non-clearing tranches to manage security of supply – see details below.]
		Percent of offers above cost	~~To stay the same over time.~~ [There is no reason why the Authority should expect the percent of high priced offers to be static when they are the primary tool to manage storage and security of supply in the face of changing market conditions]. Offer prices should reflect costs (including opportunity costs and scarcity costs). ~~but~~ There are some legitimate reasons for having a tranche with a higher offer price – ie, a "nonclearing" tranche.			Meridian and Mercury always have a higher percentage of offers above cost compared with Genesis and Contact, regardless of the storage situation. This is to be expected because the estimates of cost do not account for scarcity costs. It is also to be expected because of different generation portfolios – Meridian and Mercury do not have thermal generation and therefore use high priced offers to manage storage in a way that ensures security of supply for New Zealand. Meridian and Mercury also operate complex hydro chains that are imbalanced and require recharge and hydraulic management to ensure efficient use of resources and to meet peaking requirements. Changes in higher priced tranches in the review period are ~~However, some of this may be~~ explainable by gas supply uncertainty or hydro operating constraints, as well as changes to storage management to ensure security of supply despite gas supply uncertainty. If Meridian and Mercury did not operate in this way shortage risks would increase, and shortage entails significant economic cost to those generators and to New Zealand.
		Relationship of storage to cost	Expect a negative correlation, because the value of stored water for hydro generators increases when storage is low relative to what is expected.			Significant negative correlations for all generators in the review period, although slightly weaker correlations for Mercury (using its water values) and Genesis (using DOASA water values). This indicates water values accurately reflect one aspect of cost for hydro generators.

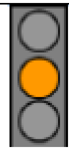
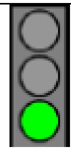
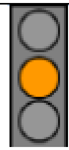
		Relationship of offers to cost	Should be a positive correlation, because we expect generators to increase their offers if their costs increase. However, any estimate of costs must include the costs associated with scarcity risk.			Meridian and Mercury's offers are not correlated with their water values using some measures. This is to be expected because our estimates of cost do not account for scarcity costs. Meridian's offers are aligned with its costs when offers >$300/MWh are excluded, this is to be expected given Meridian's "minimum sell values" do not inform offers >$300/MWh. Meridian's offers >$300/MWh are to manage the risk of scarcity in the face of increased uncertainty. We would expect to see offers correlated with cost if cost estimates suitably accounted for scarcity risk. None of the generators' offers appear to be related to the DOASA water values. This indicates that DOASA water values are not well calibrated to real world decisions faced by reservoir owners and DOASA water-valuations are misleading at best or invalid at worst.
		Lerner Index	A Lerner Index score of zero indicates perfect competition and we do not expect this in the wholesale market. However, we expect it to be … ~~To be closer to zero~~ [Closer to zero than what? The expectation cannot simply be "better than observations" – that is not a clear expectation and means the measure will always be orange as observations can always be closer to zero.] and remain about the same over time.		-	Stratford has had a reasonably high average Lerner Index during the review period, higher than in 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.~~ The Lerner Index for hydro generators is undermined by the estimates of cost applied, which (as discussed below) do not account for all relevant opportunity costs (including the impacts of scarcity). The assessment is therefore not meaningful in any way.
	Output	~~2 percent decrease in demand in the SI~~	~~A modelled decrease in demand in the SI is equivalent to SI generators shifting supply from higher priced tranches to lower priced tranches. If the average price decrease from a decrease in demand has increased, this suggests an increased incentive to economically withhold.~~		-	~~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).~~ [The test is based on the unrealistic assumption of no competitor reactions to a sustained change in supply by

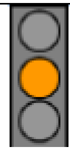
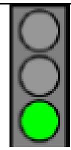
						a South Island generator. This renders the test meaningless for assessing the ability to engage in a sustained period of economic withholding. It rules out the most important aspect of workably competitive markets, which is rivalry.]
		Inter-island price separation	Should change with underlying conditions or changes in market structure, but not have any trend unrelated to these factors.			Inter-island price separation was subdued in the review period compared with previous years, when storage was high. We cannot say why there was less price separation without considering market conditions in detail however, amongst other factors, price separation will be influenced by changes in HVDC capacity. There was a change to the HVDC cable overload capacity in November 2016 which increased self-cover allowing an additional 150MW of transfer for the same dispatch of North Island reserves. There was an additional change in November 2017 to management of the loss of a second HVDC filter bank which reduced the pre event reserve requirements decreasing the quantity of reserve required to support HVDC transfers.
		Trading periods with Price separation in pre-dispatch but not in final	Offers consistent with underlying conditions, revisions in pre-dispatch consistent with underlying conditions.			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 as is to be expected to manage storage and security of supply risks over time.
		Trading periods with high prices	Offers consistent with underlying conditions, revisions in pre-dispatch consistent with underlying conditions (no obvious manipulation). Prices reflect the marginal			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

			generator as determined by underlying conditions.			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 suggest economic withholding.~~ [As discussed elsewhere extensively, 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.]
		Tiwai contracts event analysis	Any contract made in a competitive market should not be below cost. [The supposed problem identified in the issues paper was one of inefficient price discrimination rather than contracts below cost per se. Most contracts below cost will simply be a wealth transfer between two parties to a risk contract. Appendix B of the Authority's issues paper makes it clear that a high willingness to pay will not result in inefficiency but a low willingness to pay can.]			~~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.~~ The contract between Meridian and NZAS was not below cost once all factors have been properly considered including, nodal price differences between Benmore and Manapōuri, the value to Meridian of smelter demand response and other flexibility options built into the contract, an ASX benchmark that may not yet have accounted for the full risk of a smelter exit as many (rightly it turns out) still expected the smelter to remain. NZAS also has a high willingness to pay and would potentially have stayed beyond August 2021 regardless of whether the parties agreed the January 2021 contract.

Market performance	Pricing trends	~~2 percent increase in demand~~	~~When the market is competitive, any trend towards increases in demand resulting in large price increases should attract entry. A large price increase would indicate supply is limited at the current price level and a higher incentive to economically withhold.~~		-	~~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.~~ [This indicator provides no insights into whether economic withholding has occurred. It is also a mirror of the 2 percent decrease in demand and like that indicator, is based on the unrealistic assumption of no competitor reactions to a sustained change in supply and demand. This renders the test meaningless for assessing the ability to engage in a sustained period of economic withholding. It rules out the most important aspect of workably competitive markets, which is rivalry.]
		Spot market supply curve	A steeper supply curve indicates greater incentive and ability for generators to exercise market power.		-	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 the incentives to exercise market power. However, net pivotal analysis indicates a lack of incentive to do so and as Grant Read notes, participants can be expected to make their offer curves steeper, to manage both physical and financial risk, in an uncertain environment.
		Marginal analysis	No big changes in the percent of time any one generator is marginal (before 2018 and after), especially in higher priced trading periods. Any changes are consistent with underlying conditions.			Percentages of time each generator is marginal are similar to previous years, and any changes during the review period are consistent with underlying conditions. [Therefore, the indicator should be green, and anything less is indicative of some unarticulated view or belief by the Authority. The change in the frequency at which Mercury is marginal can be explained by supply and demand conditions and we have seen no evidence anything else is occurring.] 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~~.
		Actual versus predicted prices	Any deviations should be explainable by underlying conditions that are not captured by the regression explanatory variables. [Concept and Munro Duignan indicate that deviations may be explainable by underlying conditions, like gas market uncertainty, that are not captured or not fully captured by the regression explanatory variables.]			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. [It is not possible to be completely sure with statistical analysis. If the Authority applies this standard the traffic light will remain orange in perpetuity. However, all the evidence suggests prices are explained by underlying conditions. As the Authority notes, “the model confirms what we qualitatively observe about the spot market: that high spot prices tend to coincide with low wind, low storage, high gas spot prices and other gas sector disruptions, and high demand. Both the linear model and dynamic regressions provide evidence to support the hypothesis that spot prices are determined by the balance of supply and demand.” The timing of the structural break also supports a conclusion that the unexplained uplift in price is related to gas supply issues. Anyone can speculate about the price movements not captured fully by the regression, but it is pure speculation, whereas the evidence suggests this indicator should be marked green.]

		Forward prices	Forward prices should reflect expectations of future supply and demand conditions, that is, future spot prices determined in a competitive market.			The forward price was pricing in certain scarcity for some of 2021 but, overall, is unbiased. [Given forward prices are an unbiased indicator of future spot prices this should be marked green as it achieves the expectations set out.]
	Profitability	Cost to income ratio	No firm should be able to make supernormal profits on an ongoing basis unless it is linked to innovation and a pushing out of the production efficiency frontier.		-	Concept's analysis does not opine on what profits should be, only whether they have changed and their proximate causes. For most firms, earnings did not change markedly between FY 2018 and FY 2020. Meridian was the exception with an increase in earnings. [The Authority makes no finding of "supernormal profits" still less any finding of "supernormal profits on an ongoing basis." For the reasons below, Meridian believes this indicator should be deleted but if it is retained there is no reason for it to be orange and it should be green. Analysis of profits is not informative and an increase in Meridian profits across three financial years is certainly not cause for some concern (as the Authority tells us an orange light signifies). The Authority makes no assessment of whether profits are supernormal or sustained. Making judgements about economic profit based on a snapshot for a limited time period is likely to be misleading. Profit can be impacted by unexpected changes in the overall market. For example, as an inframarginal generator Meridian benefits from higher wholesale prices associated with gas supply issues. This is outside of Meridian's control. Economic profit or loss could be the result of a windfall gain/loss, unexpected financial impact or smart management. Positive economic profit does not mean that a firm is earning "excessive profits" or has exercised market power. In

						fact, in competitive markets it is the primary objective of *all* firms to increase profit.]
	Dynamic efficiency	Investment	Has there been investment in least-cost generation technology? (As supply tightens, expect an increase in investment.)			Yes, there has been investment. There are many examples of investment occurring: Waipipi, Harapaki, Tauhara, Turitea, Ngawha, Lodestone Energy solar projects, Solar Bay's Christchurch Airport project, Ruakaka Energy Park (solar and battery), and Hiringa's wind investment with Balance to name a few. Uncertainty has caused some delays, but a massive wave of investment is occurring from diverse participants. By Meridian's estimate over $2 billion has been committed to projects that will generate the equivalent of around 8% of current demand. The Authority does not say how much investment would meet its expectation only that there has been investment. On any measure, Meridian considers the recent investments in generation to be very positive. ~~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 effected 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.~~

Structure

The first part of the Authority's analysis considers the structure of the wholesale market looking at factors such as the number of competing firms and whether there are any barriers to entry.

The Authority appears to have only considered the maximum offered capacity of generators in its assessment of market structure. Unsurprisingly, generators with significant thermal plant have less offered capacity over the review period. While this may tell the Authority and the reader something about fuel availability over the review period it says little if anything about market structure, which has not changed significantly during or prior to the review period.

HHI

The Authority's analysis of the Herfindahl-Hirschman Index (HHI) for New Zealand generation shows that HHI in the New Zealand market has been slowly falling since 2004 indicating the market is becoming less concentrated over time, i.e. a greater variety of generators. HHI fell at times during the review period (largely due to hydrology) but on average was unchanged in the review period compared to earlier and has been stable since around 2014. This is largely due to a lack of demand growth and not much new generation being built during this time. The investments now anticipated by new entrant generators will further improve HHI scores in the next few years. However, the Authority selectively refers to generation investments by incumbents and suggests an increase in HHI might occur (ignoring announcements that have also been made about plant retirement by incumbents and investment by new entrants).

Rather than speculating on future HHI scores the general trend is stable and if anything, falling over time. This measure should therefore be marked as green in the Authority's traffic lights. Alternatively, HHI should not be considered at all given the Authority's observations at paragraph 5.15 that HHI is not particularly useful for measuring market structure in electricity markets because sellers with a relatively small market share may still have the ability to exercise market power and HHI does not account for the effects of transmission constraints.

Pivotal supplier indicators

The gross pivotal analysis presented by the Authority is flawed and there are better measures.

Generation capacities did not change significantly during the review period. The increase in the gross pivotal figure for Meridian is due largely to:

- an increase in South Island load;
- a decrease in offered thermal generation due to fuel availability.

Changes to gross pivotal numbers as a result of fuel availability are short term and do not indicate any long term change in competitive dynamics. With generally less gas available and many instances of unoffered thermal generation as a result, it should be unsurprising that Meridian generation has been required more often. The Authority should consider some way to include unoffered but technically available generation in its gross pivotal assessment. By ignoring it, the analysis glosses over the biggest change in the market during the review period and only looks at the generation that remained offered.

The analysis also considers the South Island to be a separate region in the electricity market regardless of whether transfer limits bind on the HVDC link (connecting the North and South Islands). It is unclear why the Authority is only interested in these two regions and the HVDC section of the transmission grid – it could choose any other transmission regions that from time to time face constraints. Looking at anything other than a New Zealand electricity market is arbitrary, especially given recent improvements in the capacity of the HVDC link.

Inexplicably, the review uses a gross pivotal analysis rather than net pivotal analysis. Vertical integration of the major generators, i.e. the extent to which their generation is contracted forward, is a key feature of the structure of the New Zealand electricity market – considering gross pivotal analysis alone completely ignores this feature. A generator is net pivotal when it has generation length relative to its contracts and some of that length is needed to ensure total supply matches total demand. Net pivotal analysis is more insightful because it shows how often a generator has not only the *ability* to set market price but also how often it has an *incentive* to do so.[39] The Authority has previously described it as a

[39] This is consistent with the approach the Commerce Commission takes when assessing vertical mergers. The Commission always considers both ability to foreclose others and incentive to foreclose. It is not enough to merely have the ability if there is no incentive to actually behave in that manner. See: https://comcom.govt.nz/__data/assets/pdf_file/0020/91019/Mergers-and-acquisitions-Guidelines-July-2019.pdf.

generator being net pivotal "when it could offer its generation at a very high price and still be dispatched at a profit, given its position in the retail, forward and FTR markets."[40]

In previous Market Performance Reviews, the Authority has undertaken net pivotal analysis. Figure 4 below is a clipping of the latest net pivotal analysis published by the Authority in February 2021. As can be seen, in 2020 all generators were net pivotal less than 0.2% of the time and the measure shows improvement relative to the pre-review period. As the Authority stated, "in most trading periods spot market prices are constrained by actual and potential competitive responses by other generators or by portfolio positions that would make increasing prices unprofitable."[41] The AEMC paper the Authority itself refers to as a source for its analytical framework notes that: [42]

> "A generator which has pre-sold a proportion of its capacity in long-term fixed price forward contracts cannot meaningfully be said to be pivotal until demand increases to the point where some of the remaining unhedged capacity must be called on in order to balance supply and demand. Formally, a generator is strictly only pivotal if demand exceeds the sum of the capacity of other generators plus the hedged capacity of the generator in question."

After years of using net pivotal analysis, and without a proper explanation as to why, the Authority has suddenly decided to only consider gross privotal analysis.

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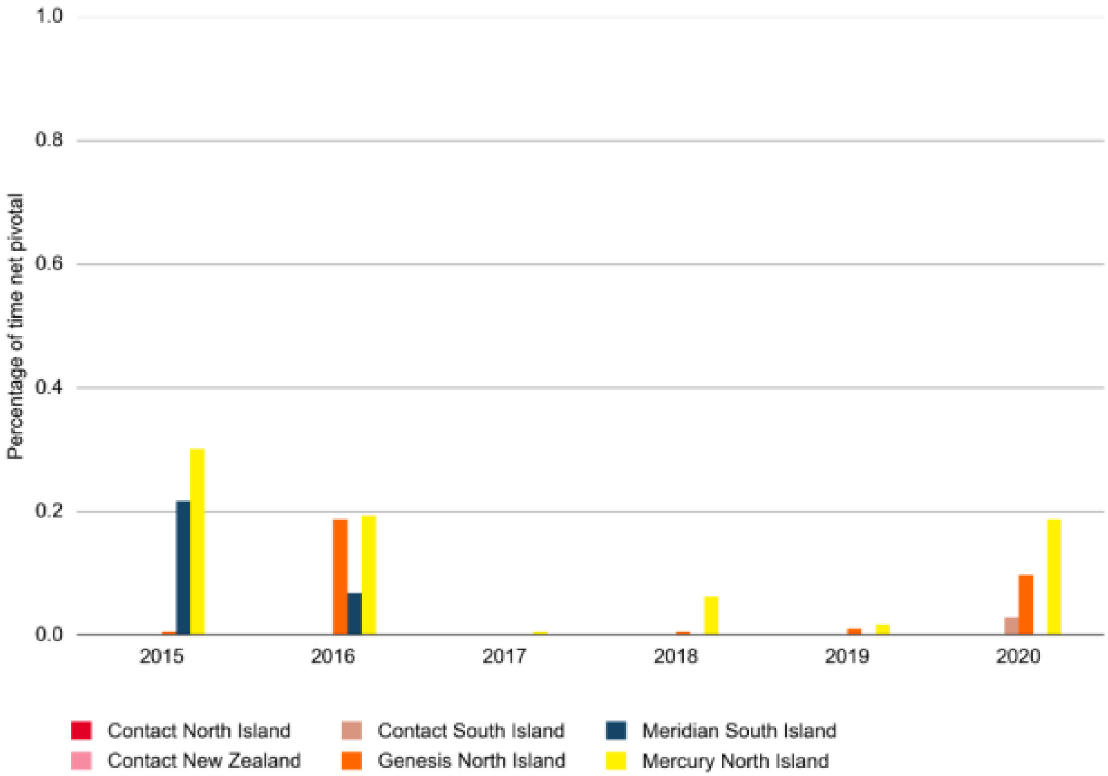
[40] https://www.ea.govt.nz/assets/dms-assets/28/Market-Performance-4th-Quarter-Review-2020.pdf
[41] Ibid.
[42] Darryl Biggar *The Theory and Practice of the Exercise of Market Power in the Australian NEM* April 2011, Page 32

Figure 4: Percentage of time generators were net pivotal



Source: Electricity Authority

Barriers to entry

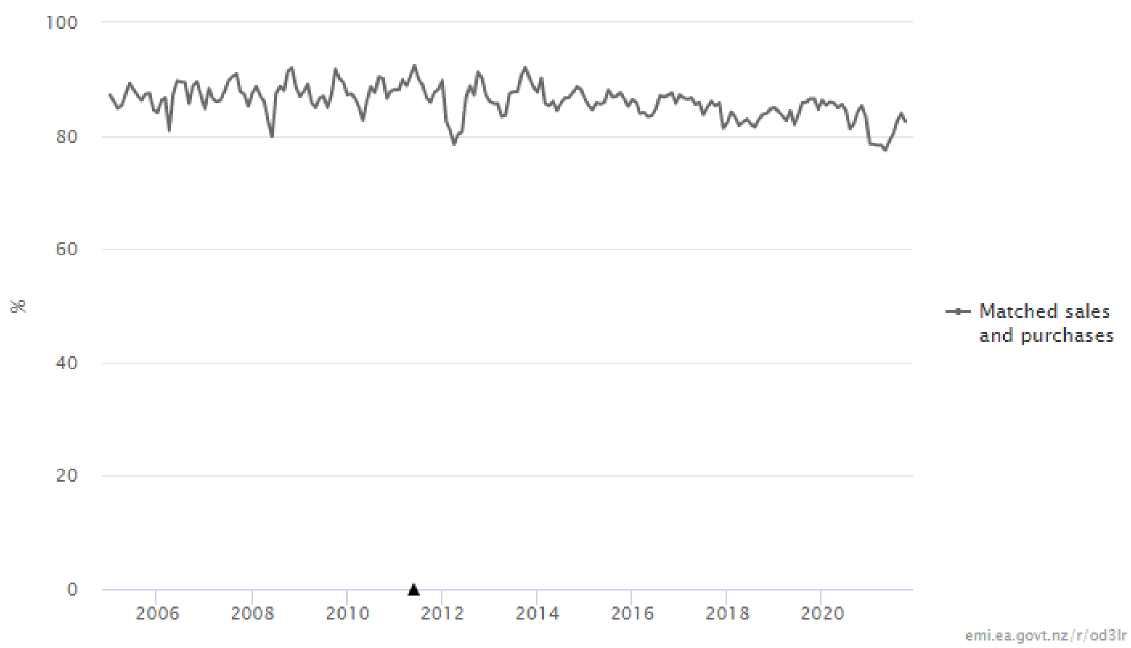
The information paper rightly considers whether there are any barriers to entry in generation. This is one of the most critical considerations to ensure the dynamic efficiency of the market. However, rather than considering this issue fully by assessing a range of potential barriers to entry like access to capital, access to expertise, or resource consenting, the Authority only considers whether vertical integration restricts the entry of new generators. The answer to this question should be obvious given the entry and expansion that has occurred in the last few years by new non-integrated generators such as Lodestone, Tilt Renewables, Solar Bay, and Hiringa Energy as well as generation investments by distribution companies such as Top Energy's Ngawha expansion. These examples are proof of market prices facilitating new renewable generation from diverse sources and suggest that there are no barriers to entry (other than those that shareholders may impose such as the requirement for a return on investment). There is nothing in principle stopping a retailer or industrial consumer from investing directly in generation or entering Power Purchase Agreements to support new generation. Clearly the shareholders of Trustpower, in separating out the generation arm of Trustpower to form Manawa Energy, do not consider they will be disadvantaged as a new independent generator.

The Authority identifies that a quarter of the committed projects and projects that are likely to be committed soon are from non-incumbent generators. This is hugely positive and it is unclear how the Authority reconciles this compelling evidence with its suggestion that there may nonetheless be barriers to entry. It is not clear how much new entry the Authority thinks there "should be". As noted in Carl Hansen's report, "with generator-retailers currently having 80% of the generation market, it is not surprising they will often account for a high share of new projects. It is very difficult to understand why these statistics are thought to be an indicator of barriers to entry; they are far more likely to be an indicator of the expertise and IP accumulated over time." If the sector was overly profitable (as is occasionally claimed), then we would see even more new entry to take advantage of the situation and erode the profits of incumbents. The levels of observed investment reflect the economics of the risk and return expectations of shareholders in new generation firms.

Comparing the level of vertical integration across the market the Authority's own data in figure 5 shows that:

- the trend is for slightly decreasing levels of integration over time; and
- levels of vertical integration are not noticeably different in the review period compared to the pre-review period.

Figure 5: Vertical integration trends across all traders (volume weighted percent)



The Authority acknowledges that vertical integration can be more efficient but suggests that vertical integration may increase costs for new entrants by reducing liquidity in forward markets and making it difficult for non-integrated firms to obtain hedges.[43] While in theory vertical integration might have that effect, in the New Zealand market that risk has already been addressed via market making in ASX futures.

New Zealand electricity futures were first listed on the ASX in 2009 and the Authority has recently taken action to enhance the futures market, with specific attention given to market making via a mandatory backstop in the Code.

In November 2021 the Authority noted that:

> "Trading activity in ASX futures products has, over the past two years, increased significantly. Trading in the period of late 2016 to 2019 was often in the range of 2,000 GWh per month. Now, in 2020 and 2021, futures trading has increased to a range between 4,000 GWh to over 8,000 GWh per month. For context, this is about twice as much electricity as is actually consumed each month in New Zealand."
>
> …
>
> "Over the same time period, October 2016 to September 2021, open interest has increased nearly 470 percent from 3,472 GWh to 19,809 GWh."
>
> …
>
> "Generally, more volume, both through increased trading and increased open interest in the hedge market creates more opportunities for generators, retailers, and large consumers to effectively manage spot price risk." [44]

In a 2019 paper the Authority noted that "steadily increasing open interest and trade volumes suggest the futures market is, at least to a significant extent, enabling participants to manage risk. Even during market stress events, such as in 2018 and 2019, the Authority has not seen direct evidence there was insufficient volume of contracts available in the futures market." The Authority went on to say that the market data "is difficult to reconcile with the anecdotal concerns expressed by some participants relating to insufficient volume of contracts available for trade."[45] This is even more so the case now given the significant increase in open interest and traded volumes since the Authority's November 2019 discussion document.

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[43] *Information paper* paragraph 5.28

[44] https://www.ea.govt.nz/about-us/media-and-publications/market-commentary/market-insights/market-insight/

[45] https://www.ea.govt.nz/assets/dms-assets/26/26019Hedge-Market-Enhancements-discussion-paper.pdf

It is therefore both incorrect and to some extent self-contradictory for the Authority to now suggest hedges are unavailable because of vertical integration and that this is a barrier to new generation entry (which on the contrary is clearly occurring). The Authority seeks to distinguish futures contracts as a tool for generators to manage volatile revenues, because ASX "does not have products that are long enough to cover revenue certainty for investment projects". While twenty-year futures are not available on the exchange, a new generator can enjoy considerable revenue certainty by purchasing long-dated hedges on a rolling basis. A new generator can of course also decide to adopt a vertically integrated business structure – that is a choice available to any business and we understand that Lodestone Energy is expecting to also retail electricity.

Reviews of the literature on vertical integration by Richard Meade[46] and Sapere Research Group[47] independently come to the same conclusion – there is a broad consensus that the benefits to consumers of vertical integration outweigh any claimed detriment and therefore any concerns about vertical integration are misguided.

Conduct

The conduct section of the information paper considers various indicators to analyse the price–cost relationship:

- how generators are offering into the market over time, and how these offers relate to estimated cost and storage, among other things
- the percent of offers above $300/MWh and above final price
- the percent of offers above cost, using various estimates of cost
- the relationship of hydro storage to estimated cost
- the relationship of offers to estimated cost
- the Lerner Index, which measures the margin of price above cost for the purpose of assessing market power.

Rather than assessing each of these in turn we note a range of issues across the Authority's price-cost relationship analysis. While the Authority's analysis is inconclusive, the Authority nonetheless questions the quantity of high offers for some generators and whether this indicates economic withholding. We will show in this section that:

- thermal fuel uncertainty has significant impacts that are understated by the Authority;

[46] https://cedf2c8a-aefa-4f90-be62-efeee5080c3f.filesusr.com/ugd/022795_90a6a69bdaca4de9b752db7798bf2a2d.pdf
[47] Attached to this submission.

- the Authority has not considered prudent storage management as a driver of high offer prices;
- the Authority's estimates of cost for hydro generators are unreasonable;
- the Authority's analysis oversimplifies offers by using QWOP and does not provide any meaningful insights as a result;
- the Authority's analysis needs to consider the impact of generation that was technically available but was unoffered (as opposed to only looking at offered generation); and
- the Authority's analysis needs to consider the generation portfolios of generators and the impact of those portfolios on their approach to storage and offers.

We will show that the Authority's analysis of the relationship between price and short-term cost is incapable of providing meaningful insights into the state of competition or whether generators have been exercising market power. In Meridian's opinion, the spot prices observed in the wholesale market over the period simply reflect the prevailing supply and demand conditions, including greater uncertainty surrounding gas supply and prudent storage management decisions in response to gas market issues.

The Authority has underestimated the impact of thermal fuel uncertainty

In paragraph 5.39 of the information paper, the Authority acknowledges that "in the New Zealand market, hydro generators must manage their storage levels within the context of volatile thermal fuel prices and thermal fuel availability." The Authority notes that volatile thermal fuel prices and availability can express as higher prices for thermal generation or thermal generation not being offered at all.[48] Both of these effects must be taken into account by hydro generators when assessing the opportunity cost of water to prudently manage scarce hydro resources over time. The effect of thermal generation not stepping in because of price or availability can be that offer tranches from hydro generators, which are priced to conserve water, are instead dispatched.[49] This is key. When hydro operators do not know anything about contracted gas volumes and commonly observe non-commitment from thermal generators even at very high prices, which in turn means that hydro generation volumes exceed those considered consistent with prudent storage management, hydro generators may feel compelled to offer hydro generation more conservatively to ensure the continuation of prudent storage management in the face of this uncertainty. If hydro generators did not factor in all these considerations in their offers, storage would be rapidly

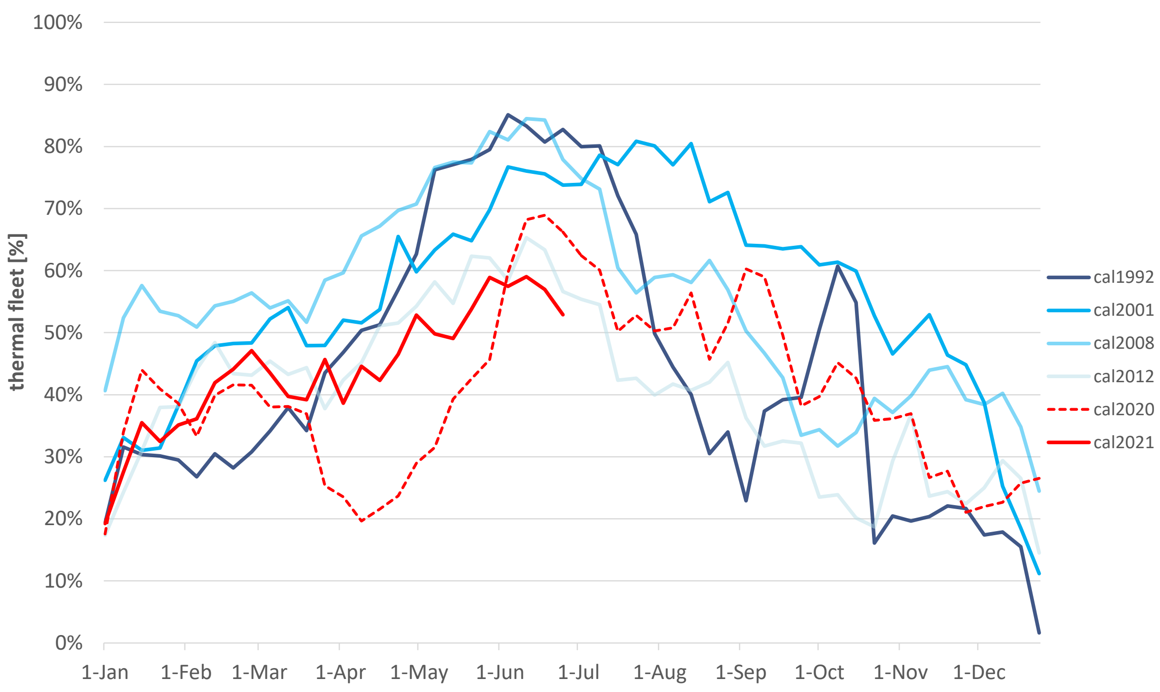
[48] *Information paper* paragraph 5.39
[49] *Information paper* paragraph 4.38

drawn down and the risk of scarcity would quickly increase. All the Authority's conduct measures overlook this primary driver of higher priced hydro tranches.

Table 9 of the information paper shows that thermal offers are commonly above the Authority's estimate of thermal SRMC. Hydro generators must take thermal offers and commitment at face value and update water values and storage management assumptions to account for that observed thermal behaviour. Not doing so increases the risk of running out of water.

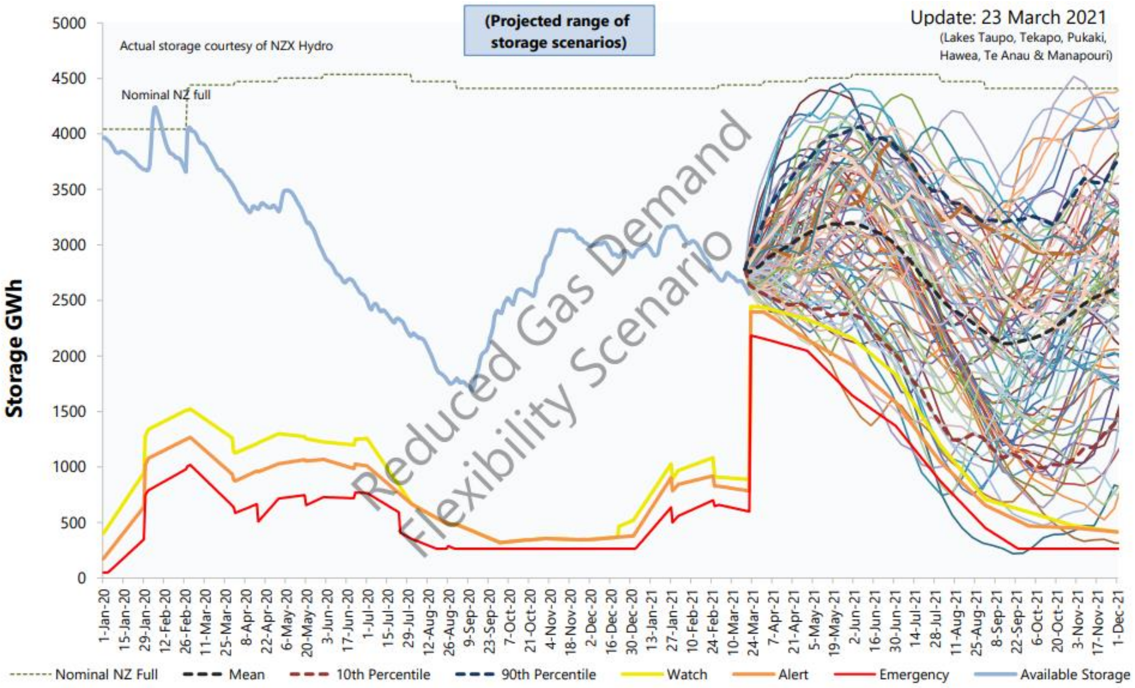
While gas prices have clearly increased, the nature of thermal availability and commitment has also changed markedly, yet the Authority's analysis looks only at offers made and does *not* consider the impact of offers not made and the general lack of thermal commitment. In previous dry-years (1992, 2001, 2008) the thermal fleet committed strongly in response to periods of high prices and low inflows, reaching 80 to 85 percent of available weekly capacity. This behaviour is less evident today. As can be seen in figure 6, in 2020 and the first half of 2021 the thermal fleet has struggled to maintain a weekly capacity of more than 60 percent. The missing 400 to 500MW of discretionary thermal generation that would normally be expected to respond to market conditions and profit-taking opportunities, instead could result in hydro storage reservoirs being depleted faster than expected, at a rate of an additional 60 to 70GWh per week.

Figure 6: Weekly thermal commitment in energy constrained years (% of installed capacity)



Hydro generators must also make assumptions (with a high degree of uncertainty) about whether, during an extended dry period, thermal generators would contract for additional gas and that gas will be available and deliverable, i.e. gas diverted from industrial gas consumers. In March 2021, the system operator modelled scenarios with and without gas demand flexibility and the resulting step up in the Electricity Risk Curves (shown below in figure 7 as occurring at the end of March 2021) demonstrates the extent of uncertainty regarding gas generation and the considerable difference that assumptions like this can make to assessments of storage risk.[50]

Figure 7: New Zealand available storage and status curves (March 2021)



Source: Transpower

Improved information disclosure about contracted thermal fuel would help to reduce this uncertainty but there has been a lack of meaningful action to date.

Offers indicate a desire to prudently manage storage over time

The Authority's assessment of the price cost relationship in generation offers exhibits many shortcomings. For example, simple analysis of the percentage of offers above $300/MWh reveals little – if anything – about the state of competition in the wholesale market when

[50] https://www.transpower.co.nz/sites/default/files/bulk-upload/documents/Reduced%20Gas%20Demand%20Flexibility%20Scenario%20-%20March%202021.pdf

those offers may simply be signalling the opportunity costs associated with scarcity. The attached report from Axiom Economics discusses this in further detail.

Paragraph 5.46 of the information paper is wrong to assert that offers above $300 could indicate economic withholding. The information paper should have also provided the balance of other reasons, such as hydro generators managing generation volumes with non-clearing tranches for the purposes of:

- plant optimisation;
- managing river or canal chain hydraulic constraints (including reservoir recharge to enable peaking); and
- ensuring long-term volumes are appropriate to manage security of supply across various time horizons.

For Meridian, an offer price of above $300/MWh would typically signal that this is generation which is technically available in the current period if there a system stress event in the market, but otherwise should not be dispatched. That is, if this water was used period-after-period then the risk of a water shortage would increase beyond our level of risk tolerance.

Hydro generators, particularly those without thermal plant, have always conserved volume to cover future contracts and to avoid the reputational and regulatory or political risks associated with shortage. It should come as no surprise that the increase in thermal fuel scarcity and uncertainty would result in an increase in the use of non-clearing tranches by hydro generators.

In places, the information paper acknowledges that economic withholding could be due to reasons other than trying to influence the price[51]. However, the information paper is strangely silent on what would constitute a "reasonable" quantity of offers at non-clearing prices as opposed to "too much" offered at non-clearing prices. There is no discussion about whether the hydro storage outcomes over the review period represent a reasonable degree of risk aversion or what any change in offers would do to the risk of shortage. Whenever the Authority mentions the potential for economic withholding it is in fact talking about storage management considerations.

Meridian is fortunate to hold around 40 percent of New Zealand's hydro storage in Lakes Pūkaki and Ōhau (1766GWh). With that storage, comes the responsibility of ensuring that

[51] For example, at paragraph 5.104

storage is prudently managed. Despite being the largest storage lake in Aotearoa, lake Pūkaki has relatively little storage and can be rapidly depleted. To take an example, if in one month Meridian offered all available Waitaki capacity at clearing prices we would use up to 918GWh of storage in the month. If inflows were 300 to 400GWh in that month (as was the case for much of 2021) this approach would create an enormous storage problem in a very short space of time.

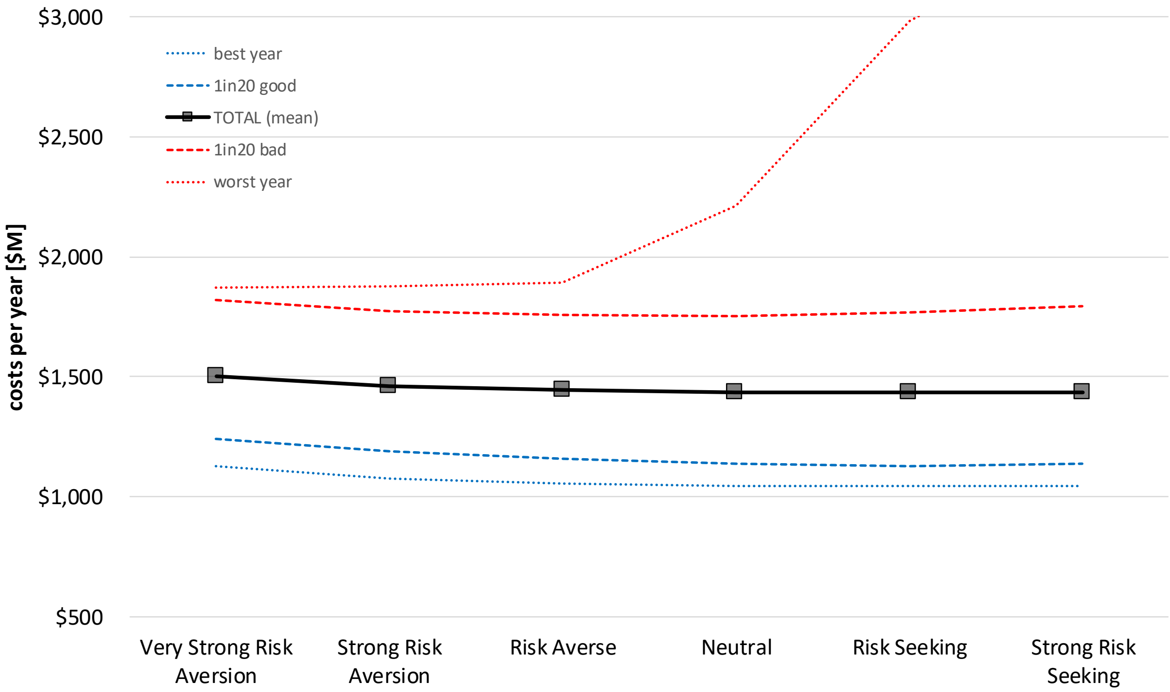
To manage massively uncertain inflows and uncertainty regarding how other market participants will behave, Meridian uses a market model to manage our storage. The model is given 87 historical hydrological inflow sequences to help it predict the range of potential inflows in future and therefore future storage levels. In doing so, the model can recommend a range of generation volumes over the model horizon and indicate what level of shortage risk is associated with the future.

Additionally, Meridian's generation is constrained by hydraulics. The Waitaki scheme has several intra-chain lakes. The cumecs that can be passed through each station do not perfectly match the upstream stations plus local tributaries (plus any necessary upstream spill). This can be exacerbated by outages. Put simply, the total generation must be less than or equal to the average flow of the station with the lowest ability to flow water over the timeframe of storage capabilities (accounting for tributaries). Lakes must also be "charged" to meet full capacity – the lake above a generating station must have water in it, but not so much so that it impacts the output of the upstream station. When inflows and generation are low, "recharging" the lakes from a peak can be challenging. Recharging is often done overnight but is also more difficult overnight due to low demand.

Storage management can be considered through an economic risk aversion framework, similar to the methodology used by the Authority when deriving winter energy margins. In a risk seeking setting we can expect higher system running costs (more thermal fuel burn and shortage costs in extremes) but limited additional generation capacity required in reserve and less spill. In a risk averse setting we can expect lower system running costs (less thermal fuel burn and less shortage costs in extremes), but potentially significant costs for additional generation capacity in reserve and more spill. An optimal setting on the risk spectrum will balance total system costs for New Zealand both on average and in extremes.

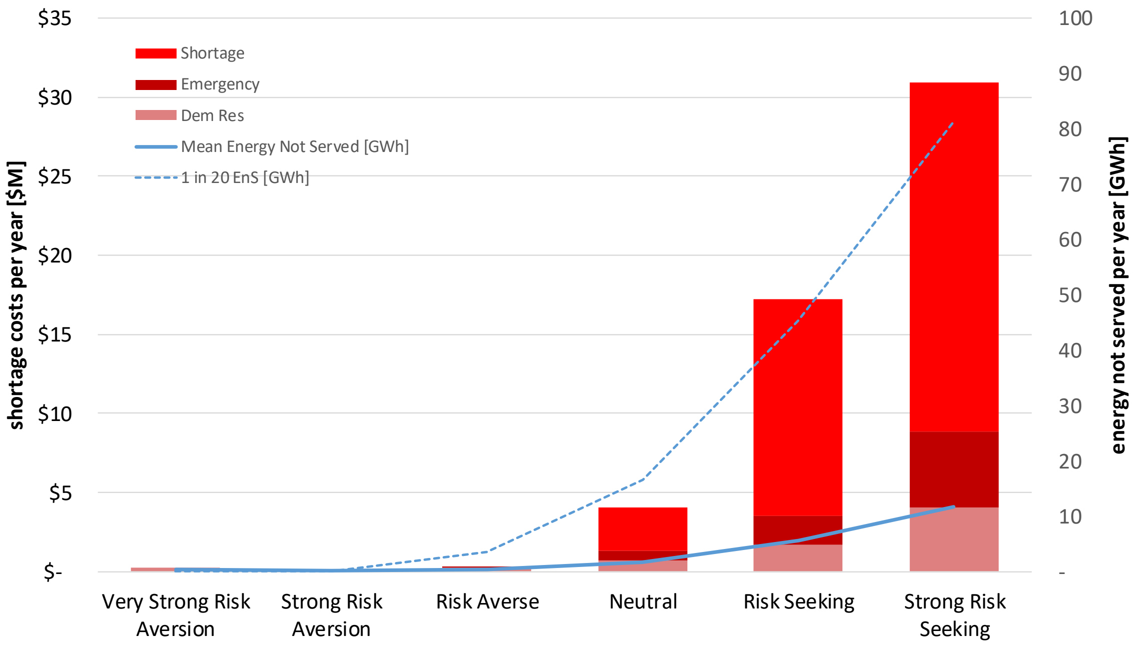
A wide range of storage outcomes are possible and with very similar *average* system costs. However, when we consider the full range of hydrological outcomes, the change in system costs becomes pronounced as shown in figure 8 below. Risks associated with the fear of reaching the bottom of the storage lakes have long dominated energy market design in New Zealand and carry significant risks, especially for Meridian. The politically problematic worst case can be significantly improved as risk aversion is applied – the worst case (extreme dry-year) system cost outcomes become significantly better with around $1.5 billion improvement in dry-year cost outcomes.

Figure 8: Total system costs and storage risk attitude (all weeks, all hydrologies)



The more aggressive the storage management pursued the greater the likely frequency and depth of energy not served (lights going out) and the higher the associated costs to the economy, as shown in figure 9 below.

Figure 9: Annual shortage costs and storage risk attitude (all weeks, all hydrologies)



An increase in system hydro spill is seen as risk averse behaviour increases, this is an unavoidable consequence – it is not possible to simultaneously minimise spill and maximise system security. The assessment made by Meridian is that storage management that applies modest risk aversion is in the best interests of New Zealand and in the best interests of Meridian commercially.

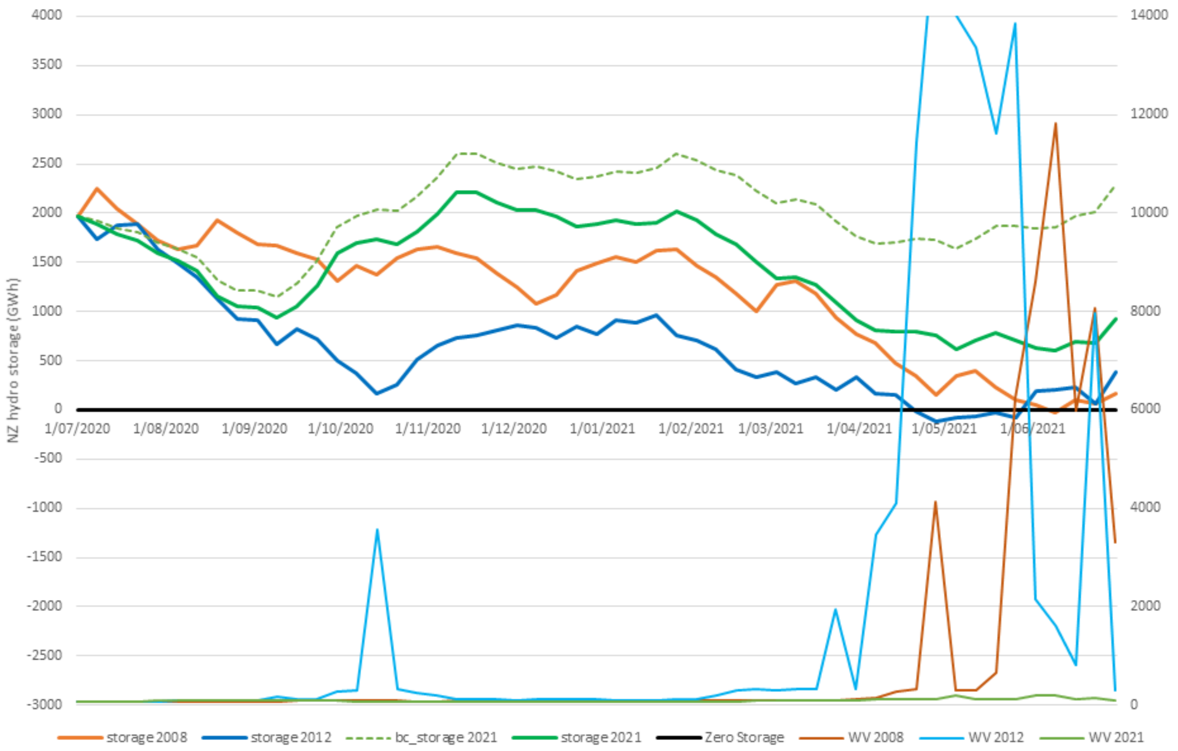
To suggest prudent storage management could be "economic withholding" does not recognise the purpose of non-clearing offers to manage finite stored water, with uncertain supply in future, and uncertain behaviour from other market participants. We find this particularly puzzling given the Authority's focus on security of supply issues – recent examples include the future security and resilience project, the independent review of the 2021 dry year, review of 9 August 2021, and work with the Security and Reliability Council.

In New Zealand's hydro-centric system, potential water shortages are only ever a few months' away. Shortage risks must be factored into offers in some fashion. For example, Meridian could have more periods in which it offered a greater proportion of its capacity at prices below $300/MWh. However, this would inevitably be offset by more periods with offers well above $300/MWh when storage levels dropped. As discussed in the attached reports from Grant Read and Axiom Economics there is no reason to think that this steeper water value curve would result in different average prices overall. It is also far from clear that customers would benefit from the greater price and storage volatility that might result.

The Authority's analysis does not explore the direct link between hydro offers and the security of supply implications of the resulting storage outcomes. As an example of the sort of analysis the Authority might like to consider, we have previously suggested hindcasting. Alternatively, the Authority could run the vSPD model to examine the storage and price outcomes that would have resulted in various years if hydro storage was offered at the water values produced by the DOASA model and looked up by the Authority in the information paper. Meridian has prepared some examples below in figure 10. The dashed green line of actual 2021 storage outcomes is compared to storage and offer prices with DOASA look up values in 2021. We also modelled what 2021 would have looked like using DOASA water values but with a drier inflow sequence (using 2008 and 2012 inflows). In short, DOASA water values do not rise early enough to dispatch enough offered thermal generation to prudently conserve hydro storage, leading to:

- Storage approaching close to the Official Conservation Campaign start trigger in 2021 – an extraordinary outcome as 2021 was drier than average, but not very dry.
- In 2008 and 2012 New Zealand would have run out of controlled hydro storage and there would not have been enough total thermal offers to avoid energy shortage, therefore load shedding would have been likely over significant periods of time. This shortage is reflected in the *very* high DOASA lookup water values. If hydro generators had behaved in this way, they would undoubtedly have faced considerable backlash from stakeholders, regulators, and politicians.

Figure 10: NZ hydro storage outcomes using DOASA water value lookups for 2008, 2012, and 2021 inflows solved using vSPD



Any commentary from the Authority suggesting hydro offers could have been different is a suggestion that storage management should have been conducted differently. The Authority is entitled to suggest this would be a better outcome for New Zealand, but it has stopped short and considered offer prices in isolation from storage. The Authority has not in any of its extensive analysis described any counterfactual storage scenarios nor the implications for security of supply.

What the Authority frames as a conversation about potential economic withholding is in fact a conversation about prudent storage management and the level of risk aversion that is to be expected in this market. Previous regulatory interventions have pushed hydro generators to be more risk averse and the Authority now seems to be signalling a potential nudge in the opposite direction, without considering if the storage implications would actually be better for the country. This is particularly unhelpful because the Authority has not approached the question of storage management directly but has instead chosen to cast doubt about the potential for economic withholding for revenue purposes without considering the inevitable storage implications of that action in any way.

Meridian shared its modelled optimal generation volumes with the Authority prior to publication of the review papers. The very close correlation between actual generation and modelled optimal volumes is direct evidence that the statistically unexplained uplift in prices is (at least for Meridian's part) *not* attributable to the exercise of any market power but rather the offers that were required to deliver prudent storage management in the face of increased uncertainty about gas generation and limited gas flexibility. Meridian's storage management has evolved over several decades and has been tested through a large range of market and weather-based events. We consider Meridian's risk appetite in respect of storage to be appropriate both to manage Meridian's risk and to ensure security of supply for Aotearoa.

The cost benchmarks used are not reasonable

The Authority compares offers with two different Authority estimates of short run costs:

- water values provided by the generators themselves – in Meridian's case, its so-called "minimum sell values"; and
- water values from the DOASA model looked up for actual storage levels.

Neither of these is a reasonable estimate of costs that would appropriately include the cost of managing scarcity risks.

Meridian's minimum sell values are not an estimate of Meridian's opportunity cost for water – they are guidance for traders in respect of a sub-set of Meridian's offered capacity. Crucially, the minimum sell values do not inform:

- generation offers that are priced at close to zero to cover Meridian's contracted volumes; or
- even more importantly, generation offers that are priced at a level not intended to clear in a typical trading period, i.e. offers that are intended to signal the opportunity costs of scarcity consistent with prudent management of storage lakes.

Without these non-clearing tranches there would be a constant risk of Meridian not being able to manage storage. That is, if that capacity was dispatched on an ongoing basis then security of supply risks would be accentuated, the risk of shortage could rapidly increase, and poor outcomes for Meridian and New Zealand would become increasingly likely.

By not factoring in the opportunity cost of scarcity, the Authority's use of minimum sell values as an estimate of hydro SRMC is implausibly low. As detailed in the attached report by Axiom Economics, it is telling the information paper notes that if all of Meridian's offers above $300/MWh are removed, then there *is* a positive correlation between offers and the Authority's cost estimate. As Axiom notes, the potential corollary of this is that, if the

$300/MWh offers were left untouched, and the SRMC estimates were increased to reflect more accurately the opportunity costs of managing scarcity, then both variables would incorporate some measure of opportunity costs (albeit imperfectly) and a positive correlation is more likely to emerge between them. It is precisely through offers priced above $300/MWh that Meridian provides a signal to the market of the scarcity value of its water and ignoring this makes the Authority's analysis meaningless.

The second of the Authority's estimates of cost is no more meaningful. Meridian has carried out a detailed review of the DOASA model. In short, the data inputs for DOASA combined with the model configuration define an approach to the New Zealand hydro-thermal problem that is not well calibrated for the planning decisions faced by prudent reservoir owners. In many areas, assumptions and methodology combine to define less stressed water valuation that understates security of supply storage risks. Consequently, conclusions based on DOASA water-valuation or implied reservoir management drawn from current DOASA runs are misleading at best or invalid at worst.

In addition to the shortcomings of the DOASA model, the Authority's use of that model in its analysis is inappropriate. Rather than describe a counterfactual storage management scenario based on DOASA water values *and the resulting storage releases* the Authority has simply looked up DOASA water values based on actual storage week on week. This only confirms what was already known, which is that DOASA consistently estimates marginal water values that are lower, for the same storage levels, than real world hydro operators. This approach tells the Authority nothing about the implications of that lesser water valuation for security of supply. As noted in the attached report from Grant Read, lowering marginal water values, for whatever reason, has much less effect on outcomes in the real world, or in simulation studies, than is commonly supposed. The effect is just to shift the whole probability distribution of storage trajectories, without necessarily lowering prices on average.

As we have demonstrated, following DOASA's recommendations would have produced a lower set of storage trajectories than those observed in the market, along with higher shortage probabilities and price volatility. The Authority should consider whether the nation would have considered itself better or worse off under that regime, or whether average prices would have been significantly affected.

QWOP is not robust

The Authority's analysis relies heavily on one measure of offers – Quantity Weighted Offer Prices (QWOP). Generators offer in up to five price-quantity tranches per generating station. QWOP averages all offers across all stations in a catchment to a single price. This gives a highly oversimplified view of offers and any findings based on QWOP will be relatively meaningless. QWOP is also a flawed measure because it only considers generation plant that is offered into the market. This means QWOP overlooks a major issue with the period since late 2018 – the amount of unoffered thermal plant.

Legitimate differences in bidding strategies can result in large divergences in the resulting QWOP value. Section 4.2.1 of the Axiom report, provides some simple illustrations, using a hypothetical hydro generator's offers and changes to the offers that would have no impact whatsoever on market clearing prices but would significantly affect QWOP. For example, Meridian could decide to not offer a proportion of its capacity, i.e., to physically withhold it. Physically withholding capacity from the market is the economic equivalent of offering that capacity at a very high or infinite price. Yet, the analysis in the information paper is incapable of capturing this nuance. Ironically, physical withholding would serve to substantially reduce the proportion of Meridian capacity offered above $300/MWh and therefore improve the Authority's measure.

As described elsewhere in this submission, offers above $300/MWh serve a legitimate storage management purpose and a way to make capacity available for system stress events while still ensuring that storage is conserved. By using QWOP to assess offers, the Authority creates a perception that the regulator would prefer physical withholding to conserve water – this would lead to worse security of supply outcomes for consumers.

The analysis needs to consider unoffered generation

The Authority adopts a form over substance approach by treating physical withholding with less suspicion than economic withholding. For example, at paragraph 5.42 of the information paper, the Authority notes that: "We are interested in the quantities of electricity offered at high prices. If these higher priced offers are not related to operational or underlying supply and demand reasons, it could indicate economic withholding (ie, offering some quantity at higher prices for the express purpose of reducing supply and increasing the spot price)." As we have shown, Meridian's higher non-clearing offers are related to underlying supply and demand conditions, particularly the need to prudently manage storage over time.

However, the Authority does not seem to have the same suspicions about physical withholding – in fact the analysis ignores it entirely and no purpose is attributed to or suspected in respect of physical withholding.

Meridian considers a more balanced approach would be for the Authority to include technically available (i.e. not on outage) but nonetheless unoffered generation in its analysis and that it could do so by inferring a high non-clearing price for that generation which is physically withheld. This would enable a more apples-to-apples comparison of offers across different types of generation and would likely be more insightful than the current approach of only considering offers and not the main problem since 2018, which is unoffered generation resulting in a lack of thermal commitment. Excluding unoffered generation from the analysis thus makes generators who do not offer thermal plant look more favourable than those who offer all plant at all times to help manage capacity requirements and in case of system events.

Meridian has recreated all the Authority's analysis in Tables 8 to 12 and 17 to 18 of the information paper to show alternative results once unoffered generation is accounted for. To do this we assume that all unoffered generation that is not on an outage and otherwise technically available would be offered at $301/MWh. As an example, figure 11 below recreates the Authority's Table 8 from the information paper.

Figure 11: Recreation of the Authority's Table 8 (Percent of offers over $300/MWh, by storage level)

Period	Storage level	Mercury (Waikato)	Meridian (Waitaki)	Genesis (Tekapo)	Contact (Clutha)	Stratford	Huntly
2014 to September 2018	Low hydro storage (less than 80% of mean)*	~~15~~ 19	29	~~14~~ 26	~~15~~ 19	~~1~~ 30	~~5~~ 25
	High hydro storage (greater than or equal to 100% of mean)	~~6~~ 12	23	~~2~~ 19	~~0~~ 10	~~1~~ 46	~~4~~ 48
2019 to June 2021	Low hydro storage (less than 80% of mean)*	50	33	~~29~~ 33	40	~~39~~ 45	~~11~~ 23
	High hydro storage (greater than or equal to 100% of mean)	41	25	~~4~~ 11	~~10~~ 24	~~37~~ 57	~~13~~ 41

As can be seen, the results for thermal offers over $300/MWh (or not offered at all i.e. at infinite $/MWh) are very different. Accounting for unoffered generation using a method like this is necessary for an apples-to-apples comparison across different generators. It is not reasonable for the Authority to express concern with hydro generation offers over $300/MWh while ignoring unoffered generation. Analytical approaches which appear to give a free pass to unoffered generation risk perversely incentivising generators to physically withhold generation rather than offer generation at prices which are expected to deliver prudent storage management while making capacity available for rare system stress events.

The analysis needs to consider generation portfolios

Paragraph 5.44 of the Authority's information paper acknowledges that:

> "…generators are managing plant with different characteristics. For example, thermal peaker plants are only required to run at times of high demand so have a different offer profile from thermal baseload. Offers from hydro generators managing storage will have a different profile from hydro generators managing run-of-river schemes (although this

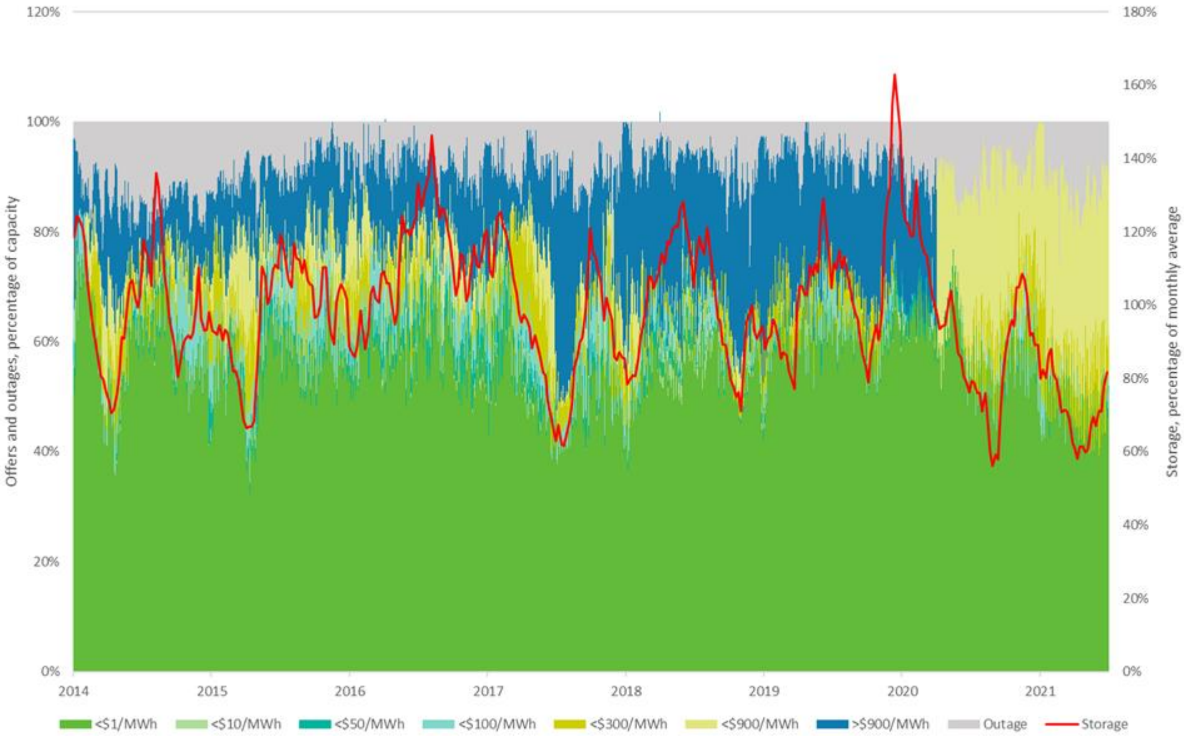
> should be reflected in water values). Additionally, hydro generators that also have thermal generation (Contact and Genesis) may be in a better position to more aggressively draw down available hydro storage, because they are able to cover their contracted load by turning on thermal generation if hydro storage gets low."

However, this acknowledgement of generation portfolios is not carried over into the Authority's analysis. For example, paragraph 5.50 notes that "Meridian (Waitaki) and Mercury (Waikato) higher priced offers are less related to storage than the other hydro generators." Meridian and Mercury offers are also compared unfavourably to the more limited use of high priced tranches by Genesis (Tekapo).[52] Paragraphs 5.66 and 5.67 make similar findings. In respect of all these statements, the distinction is obviously that Meridian and Mercury do not have thermal plant to turn on, so manage storage lakes to reduce shortage risks using higher offers. The commercial implications of shortage are significant for hydro generators who would be short and purchasing from spot to cover contracts at very high prices. This commercial incentive to manage shortage risks aligns with the national interest in security of supply. Generators with a thermal fleet do not share this risk, at least not to the same extent.

The Authority's analysis also looks at individual hydro catchments in isolation. This is not how generators operate in practice. For example, high lake levels at Manapōuri necessitate increased Manapōuri generation and can enable a reduction in the use of Pukaki water, which can instead be stored. Conversely, when Manapōuri experiences low lake levels, additional storage from lake Pukaki can be used to cover Meridian's contract position. Managing storage across different catchments is a way to freely transfer risk and enables security of supply to be managed more efficiently in the best interests of consumers. At figure 26, the Authority assesses the correlation of Waitaki offers with storage. As an example of a portfolio view of offers, that figure has been recreated below. As shown, there is an even tighter correlation between storage and Meridian's offers across its generation portfolio. Similar analysis could be undertaken for all generators to considers offers across their generation portfolios.

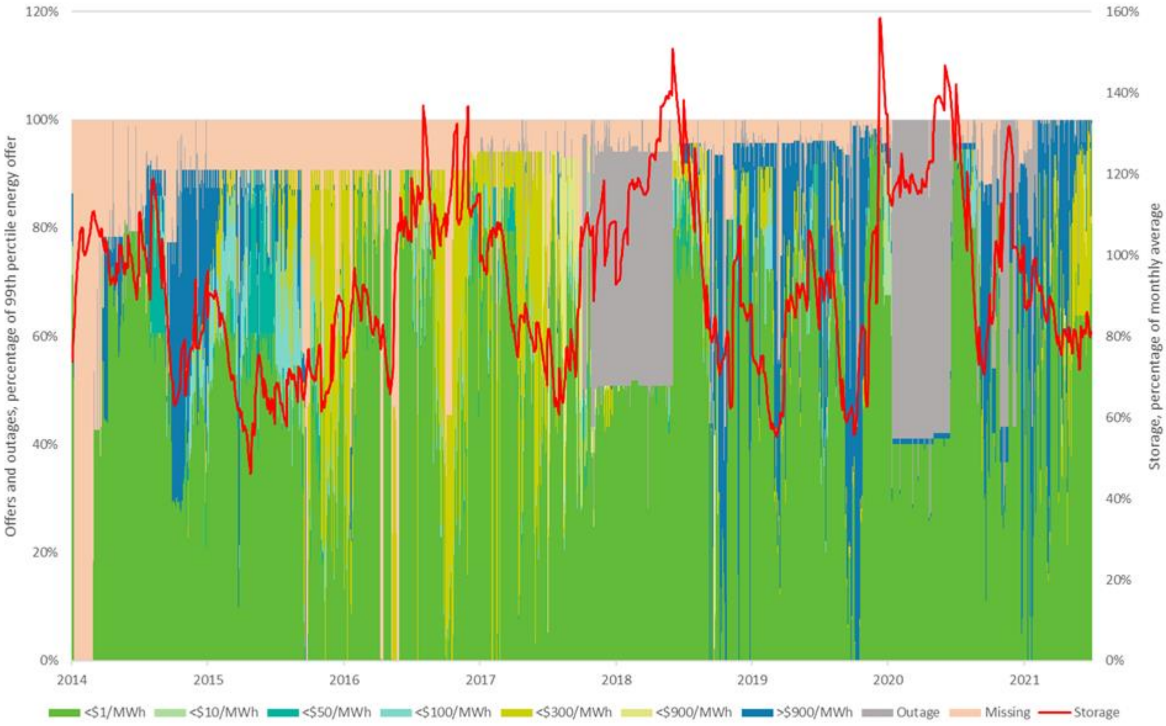
[52] It is worth noting that output from the two Tekapo stations was limited by significant outages during the review period, pushing Genesis to offer more volumes at low prices to the level of Lake Tekapo.

Figure 12: Recreation of figure 26 in the information paper showing offers and storage across Meridian's generation portfolio rather than only Waitaki generation



As an aside, and as mentioned in footnote 48, the limited use of high-priced, non-clearing tranches by Genesis at Tekapo (relative to Waitaki and Waikato) over the review period is explained in large part by the significant Tekapo generation outages during the review period. These outages caused Genesis to run the limited remaining Tekapo generation hard using low offer prices (and abandoning high offer prices) because constrained Tekapo canal flows meant the risk of shortage reduced to near zero and the risk of spill increased to a near certainty. Figure 13 below demonstrates the effect of these significant outages on offers and storage over the review period.

Figure 13: Tekapo daily offers and storage[53]



Performance

The Authority's assessment of performance considers pricing trends, forward prices, earnings by different firms, and the extent of investment in new generation.

As indicated in the summary table, and in the expert report from Carl Hansen, many of the performance measures selected by the Authority provide little (if any) information about the exercise of market power and/or do not support the conclusions reached by the Authority in its traffic light summary. Many of the measures meet the expectations set out by the Authority but the Authority inexplicably marks them with an orange "some cause for concern".

2 percent increase in demand

The assessment of how prices might respond to an increase in demand provides a static snapshot of the current supply and demand curves. It is a mirror of the 2 percent decrease in demand and, like that indicator, is based on the unrealistic assumption that no competitor reacts to a sustained change in supply and demand. This renders the test meaningless for

[53] Note that "Missing" is the difference at a trading period level between the 99th percentile total energy offer, and the sum of identified offers and confirmed POCP outages.

assessing the ability to engage in a sustained period of economic withholding. As noted by Carl Hansen, "it rules out the most important aspect of workably competitive markets, which is rivalry."

Spot market supply curve

A steeper supply curve does not tell the Authority anything about the potential exercise of market power. For example, Meridian could offer a greater proportion of its capacity at prices below $300/MWh. However, over time this would inevitably be offset by more periods with offers well above $300/MWh when storage levels dropped. As discussed in the attached reports from Grant Read and Axiom Economics there is no reason to think that a steeper water value curve would result in different average prices overall. It is also far from clear that customers would benefit from the greater price and storage volatility that might result.

As Grant Read notes, participants can be expected to make their offer curves steeper, to manage both physical and financial risk, in an uncertain environment. Concerns about the steepness of the supply curve are therefore misplaced. A steeper supply curve reflects market fundamentals and provides no evidence of the exercise of market power.

Marginal analysis

At least one generator must by definition be marginal in every trading period, that is an inherent feature of the market design. Generators also do not have any certainty when making offers in advance of real-time that their offer will be marginal, therefore there is a risk that any increase in an offer price will result in that offer not being dispatched. Therefore, being marginal does not necessarily indicate any ability or incentive to exercise market power and certainly cannot on its own provide evidence of any actual exercise of market power. Changes in the frequency that each generator is marginal during the review period, reflect changes in underlying supply and demand. As noted by the Authority, Mercury was marginal more often due to gas supply issues and low North Island inflows. This suggests the measure should be marked green. Alternatively, the measure should not be used at all or not given a traffic light marking because, in the Authority's own words, "it is difficult to deduce anything about market power from this analysis." The orange marking indicating "some cause for concern" is entirely unjustified by the Authority's analysis.

Actual versus predicted prices

The regression model and structural break analysis "provide evidence to support the hypothesis that spot prices are determined by the balance of supply and demand."[54] The timing of the structural break also supports a conclusion that the unexplained uplift in price is related to gas supply issues. The Authority says it cannot be completely sure whether all the upwards shift in prices is caused by underlying conditions, but it also cannot be sure of the inverse. This is merely a statement of the limitations of the analysis. No one should be surprised that a lot remains "unexplained" by a statistical model. The fact the model does not explain everything, does not imply that there is an additional causal factor waiting to be discovered. As noted in Carl Hansen's attached report, the regression analysis is rigorous, but its limitations must be acknowledged. Anyone can speculate about the price movements not captured fully by the regression, but it is pure speculation, whereas focussing on the evidence suggests this indicator should be marked green.

Forward prices

The Authority states that "in competitive forward and spot markets, the forward price is the expected spot price, in other words, it is probability distribution over all possible spot prices."[55] The Authority then goes on to acknowledge that forward prices are an unbiased indicator of future spot prices (while noting that forward prices can be sensitive to scarcity observed when transacting). As no concerns are identified to justify an orange light, this measure should be marked green.

Cost to income ratio

The Authority asked Concept Consulting to review the financial data of the large generator retailers. Concept's analysis does not opine on what profits should be, only whether they have changed and their proximate causes. Positive changes in earnings do not mean that a firm is earning "excessive profits" or has exercised market power. Indeed, according to Concept "it is important to recognise that any observed step-up in earnings would not prove the exercise of market power. An earnings increase could occur for other reasons".[56] In fact, in competitive markets it is the primary objective of all firms to increase earnings. The increase in Meridian earnings is explained by Concept as Meridian benefitting from "a

[54] *Information paper* paragraphs A.34 and A.35.
[55] *Information paper* paragraph 5.170.
[56] Concept *Analysis of Generator Retailer Financial Data* page 3.

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)."[57] The Authority makes no assessment of whether profits are supernormal or sustained, nor does the Authority make any attempt to assess against any other benchmark of earnings expectations, therefore it is unclear why the Authority would mark this orange as indicating some cause for concern. That conclusion is unsupported by the analysis. This measure should be marked green or not used at all.

For further detail on Meridian's profits over the last ten years, the Authority could consider Meridian's published annual reports and the economic profit analysis undertaken by PwC.[58]

Investment

The Authority rightly states that "competition means convergence to an efficient price over time."[59] Meridian agrees. New entry means that spot prices are likely to reduce in line with the cost of new entrant generation. We therefore see investment as the single most important measure of a healthy wholesale market. The Axiom report goes into detail of why a longer-term assessment of market dynamics is more informative than the Authority's comparisons of prices to SRMC.

The level of investment that is occurring is a strong indicator of healthy and competitive market. There has been an enormous recent increase in connection requests, surging development interest in solar farms and by Meridian's estimate around $2 billion of investments are either planned or under construction, once completed these assets will generate around 8% of current demand. The investments that are occurring are in diverse renewable generation technologies and are being made by a range of different businesses including both incumbents and new entrants, for example:

- Meridian's Harapaki wind farm;
- Meridian's Ruakaka Energy Park (solar and battery);
- Contact's Tauhara geothermal plant;
- Mercury's Turitea wind farm;
- Tilt's Waipipi wind farm;
- Top Energy's Ngawha geothermal expansion;

[57] Concept *Analysis of Generator Retailer Financial Data* page 5.
[58] https://www.meridianenergy.co.nz/assets/210929-Meridian-Summary-of-Economic-Profit-calculations.pdf
[59] *Information paper* paragraph 5.185

- Lodestone Energy's five solar farms in Northland, Coromandel, and Bay of Plenty;
- Christchurch International Airport's recently announced Kōwhai Park energy precinct with up to 150MW of generation and an initial $100 million investment commitment from Solar Bay;
- Hiringa's investment with Balance in a 24MW wind farm; and
- the 20-year electricity offtake agreement between Tilt and Genesis that will enable the construction of the 75MW Kaiwaikawe Wind Farm located near Dargaville.

These are excellent examples of market prices facilitating new renewable generation from diverse sources and demonstrate that there are no barriers to entry. There is nothing stopping any retailer or industrial consumer from investing or entering Power Purchase Agreements to support new generation.

These investments are occurring after a prolonged period of no load growth. They are large projects and are not completed overnight. Furthermore the investments are occurring despite the fact that supply issues in the gas market were unforeseen and the expectation would have been for more gradual investment to meet demand growth and replace thermal as carbon prices gradually pushed thermal generation out of the top of the supply stack.

As noted in the Axiom report, there are legitimate reasons why investments have slightly lagged higher wholesale prices including consenting, construction times, demand uncertainty due to NZAS, transmission costs due to TPM reform, and Government policy. However, much of the uncertainty has diminished, investments are occurring at pace and scale, and this will serve to realign market prices with entry costs over time. It is not clear from the information paper how quickly the Authority thinks investment "should" have occurred.

The Authority suggests that the pipeline of build-ready investment projects has become thin. While this may have been the case over the previous period of low demand growth, since the 2018 increase in wholesale prices, businesses like Meridian have invested significantly in upscaling their development teams and growing a pipeline of investment options. For example, Contact has an exclusive arrangement with Roaring 40s Wind Power to develop a wind pipeline[60], Genesis has selected a joint venture partner FRV to deliver up to 500MW of solar capacity over the next five years[61], and Mercury has acquired Tilt's New Zealand

[60] https://contact.co.nz/aboutus/media-centre/2021/03/23/wind-generation-experts-roaring40s-team-up-with-contact-energy
[61] https://www.genesisenergy.co.nz/about/media/news/genesis-names-frv-australia-as-partner

operations to build its wind pipeline[62]. The race is on and competition is fierce to secure and develop options.

The suggestion that incumbent generators have an advantage through access to hydro firming carries no weight. As noted in Carl Hansen's report, "every investor has access to hydro-firming via the spot market. Presumably this is why Trustpower (now Manawa) was comfortable being a net purchaser on the spot market for more than 20 years, to cover periods when its wind and hydro plants were insufficient to meet its customer's demand." Significant cover for spot pricing risk is readily available from the futures market.

Investment has increased significantly as expected when supply and demand tighten. The extent of new investment is significant and while it will not be commissioned overnight, projects are proceeding as planned and it would not be reasonable for the Authority to suggest investments should have occurred sooner.

[62] https://www.nzx.com/announcements/376610

Appendix B: Expert reports

Axiom Economics

Carl Hansen

Grant Read

Sapere Research Group